Renewable and Sustainable Energy Reviews 33 (2014) 443–466

Contents lists available at ScienceDirect

Renewable and Sustainable Energy Reviews

journal homepage: www.elsevier.com/locate/rser

Impacts of large-scale Intermittent Renewable Energy Sources on electricity systems, and how these can be modeled

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ARTICLE INFO

Article history:
Received 5 July 2013
Received in revised form
7 January 2014
Accepted 29 January 2014
Available online 6 March 2014

Keywords:
Thermal power plants
Wind power
Power system modeling
Carbon capture and storage
Renewable energy

ABSTRACT

The electricity sector in OECD countries is on the brink of a large shift towards low-carbon electricity generation. Power systems after 2030 may consist largely of two low-carbon generator types: Intermittent Renewable Energy Sources (IRES) such as wind and solar PV and thermal generators such as power plants with carbon capture. Combining these two types could lead to conflicts, because IRES require more flexibility from the power system, whereas thermal generators may be relatively inflexible. In this study, we quantify the impacts of large-scale IRES on the power system and its thermal generators, and we discuss how to accurately model IRES impacts on a low-carbon power system. Wind integration studies show that the impacts of wind power on present-day power systems are sizable at penetration rates of around 20% of annual power generation: the combined reserve size increases by 8.6% (6.3–10.8%) of installed wind capacity, and wind power provides 16% (5–27%) of its capacity as firm capacity. Thermal generators are affected by a reduction in their efficiency of 4% (0–9%), and displacement of (mainly natural gas-fired) generators with the highest marginal costs. Of these impacts, only the increase in reserves incurs direct costs of 1–6€/MWh_{wind}. These results are also indicative of the impacts of solar PV and wave power. A comprehensive power system model will be required to model the impacts of IRES in a low-carbon power system, which accounts for: a time step of <1 h, detailed IRES production patterns, flexibility constraints of thermal generators and interconnection capacity. Ideally, an efficient reserve sizing methodology and novel flexibility technologies (i.e., high capacity interconnectors and electricity storage and DSM) will also be included.

Contents

Abbreviations: CCS, carbon capture and storage; CHP, combined heat and power; DSM, demand side management; ELCC, effective load carrying capacity; GCSI, Global Clear Sky Index; IRES, Intermittent Renewable Energy Sources; NC, nameplate capacity; LOLE, Loss Of Load Expectation; LOLP, Loss Of Load Probability; RMSE, root mean square error; TSO, transmission system operator; UCED, unit commitment and economic dispatch

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http://dx.doi.org/10.1016/j.rser.2014.01.076
1364-0321

1. Introduction

The electricity sector in OECD countries is on the brink of a large shift towards low-carbon electricity generation. This process is driven by concerns about climate change, depletion of fossil fuels, and energy security [1]. To realize the emission reduction targets put forward by the European Commission and the White House, the respective EU and US power sectors will have to reduce 2005 level CO_2 emissions by 58% and 42% by the year 2030, and even by as much as 79% and 83% by the year 2050 [2,3].

As a result, the shares of low-carbon generators in the electricity mix have been forecasted to increase. In the 2 Degree Scenario of the IEA for 2050, the worldwide shares of renewable technologies are forecasted to increase to 57% of the load served, and the shares of nuclear power plants and power plants with carbon capture are also projected to increase to 19% and 15% of the load served [4]. In the 2050 roadmap of the European Commission, wind power is projected to become the largest source of power in the EU by 2050, combined with significant shares of nuclear and CCS generators [3].

It is currently unclear how the generators of a low-carbon electricity system will affect each other, because low-carbon generators can have specific operating properties. Intermittent Renewable Energy Sources (IRES) such as wind, solar PV, and wave power require more flexibility, while low-carbon generators may be less flexible. Nuclear power plants and coal-fired power plants (which can be equipped with carbon capture) are currently relatively inflexible [4,5]. The variability and limited predictability of IRES result in a number of “power system impacts”, which can become a challenge at high penetration levels [6–10]. Holttinen has classified four short-term impacts of wind power that depend on the operational properties of the electricity generation

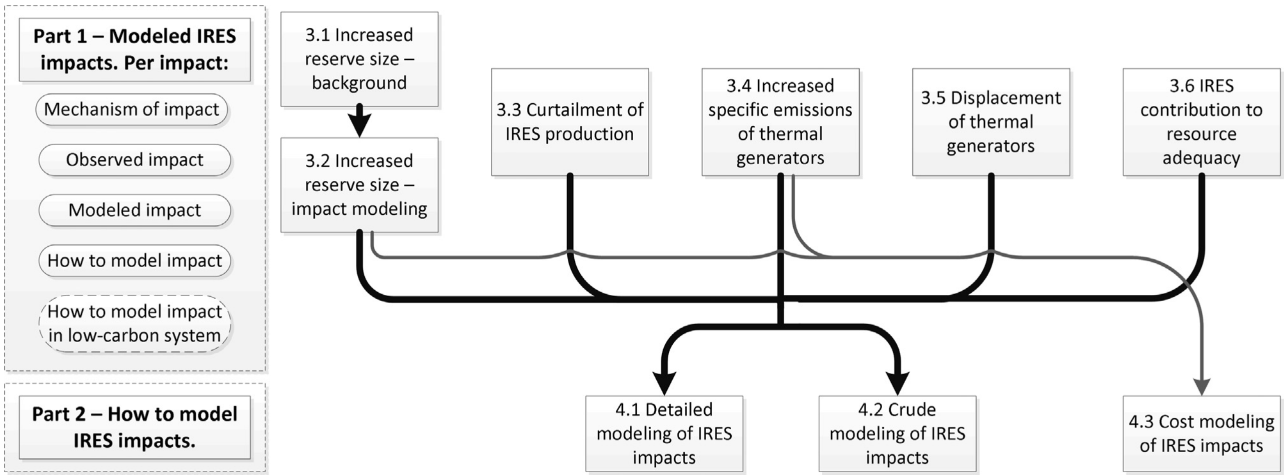


Fig. 1. Schematic overview of methodology with research steps and interactions.

technologies[1]: (1) an increase in the size of reserves; (2) less-efficient operation of thermal power plants; (3) replacement of thermal electricity generation by IRES; and (4) discarding of electricity generated by intermittent sources that cannot be absorbed by the electricity system (curtailment). One long-term impact of intermittent renewables was also identified: the extent to which they influence resource adequacy [9,11].

Many studies have investigated the power system impacts of IRES (e.g., [12–14]); however, these studies did not focus on the effects of IRES on thermal generators.[2] None quantified the effects for a future power system with large shares of low-carbon thermal generators, such as nuclear power plants and power plants with carbon capture. Instead, IRES integration studies assessed the effects of high IRES penetration on power system operation as a whole, for power systems that resemble today's in terms of generator mix. Only one study considered the costs and emissions of the flexible operation of thermal generators, and how they are affected by IRES in the Western US. [15]. In fact, a review study recommended investigating the interactions between thermal generation with varying flexibilities and wind power generation [16]. Besides this, a low-carbon energy system with IRES was considered by two studies, but these did not report on the impacts of IRES on either thermal generators or the power system at large [3,17]. More research on the impacts of large-scale IRES on low-carbon thermal generators and power systems is therefore needed, because these impacts may considerably affect the operation of low-carbon power systems, from both technical and financial perspectives.

Future research into the impacts of large-scale IRES on low-carbon power systems can be performed at different levels of detail, ranging from broad, integrated assessment models to (sometimes very precise) power system simulation models. This paper will facilitate research at all levels by answering the main question: *How large are the most important impacts of large-scale IRES on the power system and its thermal generators, and what modeling elements are required to accurately model IRES impacts on a low-carbon power system?* This is carried out by reviewing the literature on the properties of IRES power generation, as well as wind integration studies, which report on the projected magnitude of IRES power system impacts, and provide valuable findings. This study will present modeling recommendations that complement previous recommendations that focus on wind integration studies for conventional power systems [18,19].

The article consists of two parts. Part one quantifies the five power system impacts of IRES by looking at the underlying mechanisms, historical observations, the simulated magnitude of their impact in wind integration studies, and important modeling aspects. In part two, we summarize the findings by explaining how IRES impacts can be modeled with a detailed, crude, or cost-only approach.

2. Methodology

2.1. Approach

The article consists of two parts, as shown in Fig. 1. In the first part of the analysis, the five power system impacts of IRES are discussed sequentially. Per impact, the underlying mechanism is first discussed, and how it relates to the properties of IRES power production. Next, an overview is provided of the reported historical impact—if it has been quantified. Most attention is paid to the projected size of the impact as quantified by IRES integration studies. An overview of these projections is provided. Differences in projections are explained by the properties of wind energy, the modeling approach, and geographical differences. Lastly, how the power system impact can be accurately modeled is explained. For some impacts, extra modeling recommendations are made for a low-carbon power system. The increase in reserve size is a lengthy topic, and thus this impact is discussed in two separate sections.

In the second part, the way IRES impacts can be modeled for low-carbon power systems is explained based on trends from part one. Recommendations are made for the following three approaches:

(1) Detailed modeling of the impacts with a detailed power system simulation model. Recommendations are made for the factors that are necessary for accurately modeling IRES power system impacts. These general recommendations can be supplemented with the detailed recommendations that are made for specific impacts in part 1.
(2) Crude modeling of IRES impacts, with a more general regional, national, or global energy model. Based on the reported magnitude of the impacts caused by wind power, the approximate size of IRES impacts is expressed as a function of the penetration level (energy-based). These approximations allow for the inclusion of IRES impacts in models, without simulating their mechanisms.

[1] Two more short-term impacts of intermittent sources were listed by Holttinen: transmission losses and voltage fluctuations. These are not discussed in this paper as they are transmission related and, therefore, outside the research scope.

[2] In this study, thermal generators are defined as power plants that are fueled with coal, natural gas or uranium.

(3) Cost modeling of impacts, for economic evaluations of energy systems. An overview is provided of the costs of extra reserves, less-efficient thermal generation, and investments in transmission capacity. These costs have been supplied by the IRES integration studies.

The IRES integration studies were found in a literature search for studies published since 2005. This selection was made because, in terms of approach and calculation methods, recent studies are generally more advanced than older studies and they deal with higher penetration levels. Moreover, other review studies have provided overviews of these earlier studies (e.g., [16]), with which we briefly compare our findings.

IRES integration studies had to meet three requirements to be included in this review. They had to: (1) simulate an actual present-day or future power system, and provide basic information about it (e.g. generator mix, electricity demand); (2) specify the general modeling approach and assumptions; and (3) quantify at least two of the power system impacts considered. The last criterion ensures that the study comprehensively modeled electricity generation by both IRES and thermal capacity.

In practice, most studies report on the impacts of wind power, and a couple on those of solar PV power (Table 1). The extent to which the impacts of wind power apply to solar PV and wave power is evaluated in the results.

2.2. Overview of IRES integration studies

Most integration studies are based on a unit commitment and economic dispatch power system simulation model (UCED model), which generally simulates the power system with a high level of detail, both in time step (<1 h) and in the number of power sector features included. Technical constraints, reserve constraints, and interconnectors are commonly included, and some models also include grid constraints. Conventional power generation units are modeled per unit or per generator type when a large area is modeled. Dispatch decisions are optimized based on costs, and investment decisions are made exogenously.

Wind and solar PV power production is based on historical wind speed and insolation time series, commonly of one or more years, from which the power production is calculated. Studies often account for the geographical spread of projected future developments by determining the power production wind speed time series per wind farm location. Historical load data of the same period is used, which is corrected for projected future developments.

Exceptions are the UK-S, US-AR, and US-ERC studies, in which the characteristics of wind power and their effects on the power system were quantified through statistical analysis of historical datasets.

3. Modeled power system impacts of large-scale IRES penetration

3.1. Increased reserve size—background

Intermittent power production is characterized by variability of electricity production and limited predictability of this variability, both of which affect the reserve size.

3.1.1. Mechanism of increased reserve sizes

Reserves are required to maintain the short-term balance between power generation and load in an electricity system. In a system without IRES, imbalances between generation and load occur in two ways. They can be caused by contingency events (e.g., a power plant tripping), which are subsequently balanced with contingency reserves. The contingency reserve size is typically as large as the single largest contingency. Imbalances can also be caused by imperfect load predictions. Load forecasts include a forecast error, which is corrected with reserves. Because these reserves are not activated as the result of a specific event but used continuously, they are called non-event reserves. The non-event reserve size is typically 1% of the load at a given moment [31].

Both contingency and non-event reserves consist of multiple types of reserve that can be activated within different time frames. In this study, a distinction is made between a primary reserve, which is activated within 1 min (delivered by “spinning” generators), secondary/tertiary reserves, which are activated in a time frame of 1 mi to 1 h (partly spinning and partly manually activated), and hourly reserves, which are activated at time frames larger than 1 h (manually activated). Minimal reserve levels have been defined by ENTSO-E for Europe [32], and NERC for the U.S. [33]. They are often defined as simple rules based on past experience, for example as an empiric formula, or as the $N-1$ criterion where the reserve size is as large as the single largest contingency.

The definitions of primary and secondary/tertiary reserves differ per control area in terms of timescales, required size, and the type of imbalances covered [31]. In mainland Europe, “primary” and “secondary” reserves are used, which balance both contingency and non-events for timescales of 1–30 s, and 30 s to 15 min, respectively [32]. In the United States, a distinction is often made between contingency and non-event reserves, which can both be available within seconds to minutes and from minutes to hours.

The reserves are sized such that they ensure a pre-set reliability level for the whole power system (often defined as the LOLE or LOLP—Loss of Load Expectation/Probability). With the addition of IRES, the reserve sizes need to increase to maintain this level.

Intermittent sources will likely only affect non-event reserves, resulting from the uncertainty introduced by their imperfect power production forecast. This uncertainty is comparable to the uncertainty associated with load, and is treated the same way. This is illustrated schematically in Fig. 2. Power production of intermittent sources changes over time (middle graphs), and is affected by the time step that is considered as well as the geographic spread. The variation can be forecasted to a large extent (graphs on the right). The difference between forecasts and the actual power production is balanced with reserves (orange shaded area).

3.1.2. Variability of IRES power production

The variability in electricity production is largely determined by the variability of the renewable source, such as sunlight or wind. The operational properties of the installation that convert the renewable source to electricity also play a role. The installations can possess a degree of inertia, or they may be unable to function under certain circumstances, e.g., wind turbines that switch off in case of very high wind speed [34].

The variability and prediction error are quantified statistically for a specific time interval (ΔT) (Fig. 2). The difference in power output between two points in time is the delta (ΔP) in MW. The standard deviation (σ) of all deltas in an interval is the measure of the relative variability in this interval. It describes the spread of deltas, assuming they are normally distributed. Two and three standard deviations encompass 95% and 99.7% of the deltas closest to the mean, respectively [10,12].

The variability is influenced by the cross-correlation in power production between IRES generators, which is in turn affected by the spatial (geographic spread of IRES) and temporal (time step) scale of the analysis (Fig. 2). The correlation expresses the extent to which the same trends in power output occur between two generators. For the maximum correlation coefficient value of $r=1$, the variations at both sites occur simultaneously and in the same direction. At the minimum value of $r=-1$, variations occur simultaneously in opposite directions, and when the correlation

Table 1
Main parameters of IRES integration studies.

Full name of study	Abbrev. name	Region	Year(s) studied	Peak load (GW)	Load (TWh/a)	IRES type	Wind penetration (% of annual load)	IRES penetration (% of annual load)	Type of model[a]	Δt of Model	Inter connect included?	Source
Flexibility options in European electricity markets in high RES-E scenarios, 2012	EU-EWI	Europe	2020–2050	–	4092	Wind, PV	41	48	Sim	1 h	Yes	[20]
Tradewind, 2009	EU-TW	Europe	2030[b]	–	4468	Wind	13[b]	–	Sim	1 h	Yes	[21]
DENA Grid Study II. Integration of Renewable Energy Sources in the German Power Supply System from 2015–2020 with an Outlook to 2025, 2010	GER-D2	Germany	2020	–	490	Wind, PV	27	30	Sim	–	No	[22]
Integration into the national grid of onshore and offshore wind energy generated in Germany by the year 2020, 2005	GER-D1	Germany	2015	–	575	Wind	13	13	Stat	–	Yes	[23]
Integration von windenergie in ein zukünftiges Energie-system unterstützt durch Lastmanagement, 2009[c]	GER-F	Germany	2030[d]	80	539	Wind, PV	35	38[d]	Sim	1 h	Yes	[8]
Herausforderungen eines Elektrizitätsversorgungssystems mit hohen Anteilen erneuerbarer Energien[e], 2010	GER-H	Germany	2030	87.5	571	Wind, PV	27–30	30–40	Sim	1 h	No	[24]
Auswirkung der fluktuierenden Stromeinspeisung aus Windenergie auf die CO2-Emissionen fossil befeuerter Kraftwerke[f], 2007	EGER-W	East-Germany	2003	–	65	Wind	11	–	–	1 h	No	[25]
All Islands Grid Study, workstream 2B, 2008	IR-M	Ireland	2020	9.6	54	Wind, wave, tidal	47[g]	59[g]	Sim	1 h	Yes	[7]
Integratie van windenergie in het Nederlandse elektriciteitsysteem in de context van de Noordwest Europese elektriciteitmarkt[h], 2010	NL-K	The Netherlands	2017	–	118	Wind	28	–	Sim	1 h	Yes	[6]
Power System Operation with Large-Scale Wind Power in Liberalised Environments, 2009	NL-U	The Netherlands	2014	21	126	Wind	32	–	Sim	15 min	Yes	[14]
Impact of Wind Generation on the Operation and Development of the UK Electricity Systems, 2007	UK-S	United Kingdom	n/a	70	400	Wind	19	–	Stat	1 h	n/a	[26]
Solar Photovoltaic (PV) Integration Cost Study, 2012	US-AR	US-Arizona	2030	11	46	PV	8	8	Stat	10 min	No	[27]
Solar Photovoltaic (PV) Integration Cost Study, 2008	US-ERC	US-ERCOT	2008	65	287	Wind	19	–	Stat	1 h	n/a	[10]
Minnesota Wind Integration Study, 2006	US-MIN	US-Minnesota	2020	20	85	Wind	25	–	Sim	1 h	yes	[28]
Southern Power Pool Wind Integration Study, 2010	US-SPP	US-Southern power pool	2010	50	240	Wind	20	–	Sim	1 h	Yes	[29]
Western Wind and Solar Integration Study, 2010	US-WWSIS1	US- West Connect group	2017	58	286	Wind, PV, CSP	20[i]	22[i]	Sim	1 h	Yes	[12]
Western Wind and Solar Integration Study, 2013	US-WWSIS2	US-Western Inter-connection	2020	~140[j]	760	Wind, PV	16.5[j]	33[j]	Sim	1 h	Yes	[15]
Eastern Wind Integration and Transmission Study, 2010	US-EWITS	US- Eastern inter connection	2024	545	3725[k]	Wind	20	–	Sim	1 h	Yes	[13]
The effects of integrating wind power on transmission system planning, reliability and operations, 2005	US-NY	US-State of New York	2008	33	–	Wind	[l]	–	Sim	1 h	Yes	[30]

[a] Sim: simulation model, Stat: statistical analysis.
[b] Based on the medium wind scenario for 2030. The year 2020 was also studied, but not evaluated as part of this study.
[c] Translation: "Integration of Wind Power in a Future Energy System with the help of demand side management".
[d] The year 2020 was also studied, but not evaluated as part of this study. A 10% load factor for solar PV assumed.
[e] Translation: "Challenges for a Electricity Supply System with a high shares of renewable generators".
[f] Translation: "The effect of fluctuating electricity generation of wind power on the CO_2 emissions of fossil fuel-fired power plants".
[g] Wind penetration levels of 23% and 34% were also studied, which add up to 27% and 42% intermittent renewables, respectively.
[h] Translation: "The integration of wind power in the Dutch power system in the context of the northwest European electricity market".
[i] 30% Wind penetration was also included in the study, which adds up to 35% renewables, of which 31% is intermittent.
[j] The peak load is based on figure 64 from US-WWSIS2 report. The penetration shows the HiMix scenario, which is evaluated in this study.
[k] Calculated from the wind production figures for the given penetration levels.
[l] Wind power provides 10% of the peak load, or 8.9 TWh/a.

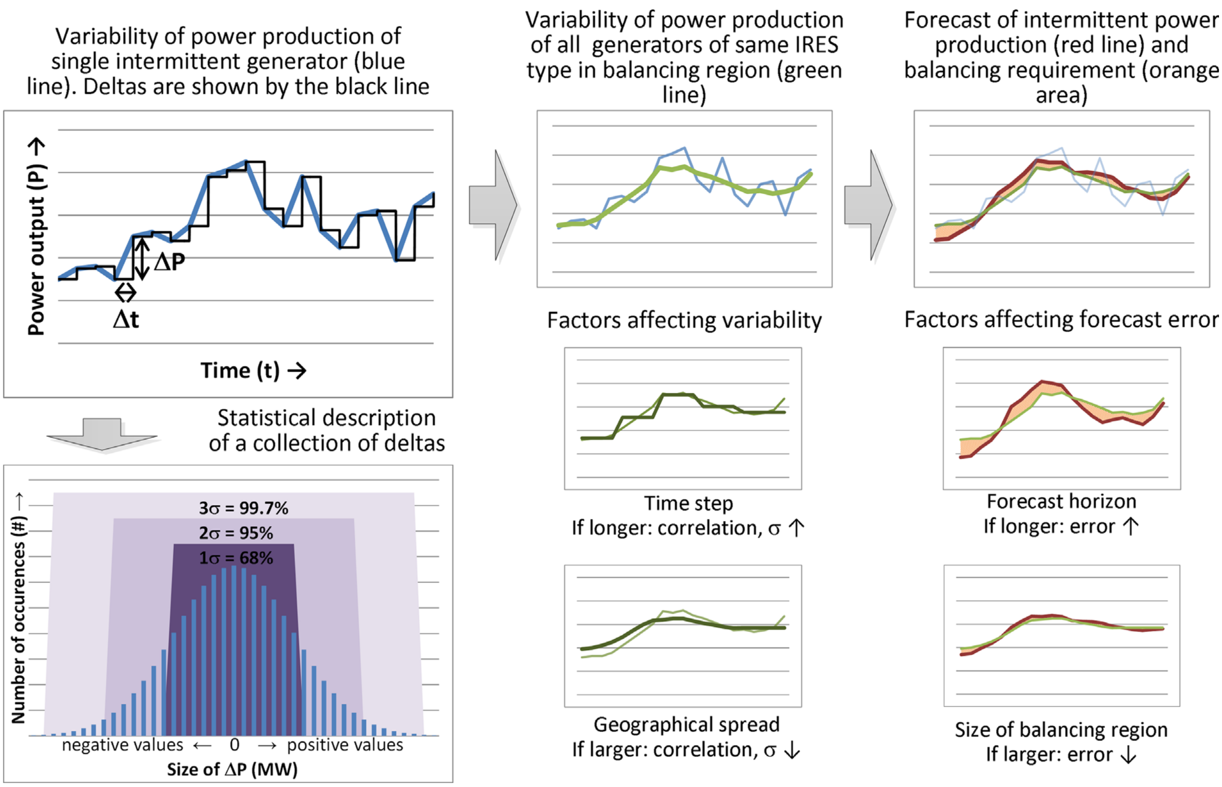


Fig. 2. Schematic overview of the variability and forecast error of IRES electricity production, based on sources in Section 3.1. (For interpretation of the references to color in this figure, the reader is referred to the web version of this article.)

is zero, the power output is uncorrelated [34]. Correlations lower than $r=0.25$ are classified as weak [35,36].

When the time step increases, the relative variability (the average annual standard deviation per MW of nameplate capacity of the generator) increases, because the probability increases that generators are affected by the same weather patterns. This results in a higher correlation (Fig. 2). As the spatial scale increases, the relative variability decreases. The larger the distance between different generators, the smaller the probability that the weather conditions at both sites are the same, so the correlation decreases [37]. This effect is called spatial smoothing [35,37,38].

3.1.2.1. Variability between IRES generators.. Historical measurements show that the variability of wind and solar PV follow similar trends (Fig. 3). The Global Clear Sky Index (GCSI) variability of solar PV, which does not include the variability caused by the daily trajectory of the sun, is lower than that of wind power. Little information is available on the variability of wave power, partly as a result of a lack of measurements [39]. Wave power shows hourly variability, but it is smaller than that of wind power [40]. The hourly standard deviation for a location off the coast of California over a period of 16 years has been reported to be 10.8% for wind and 5.1% for wave energy [36]. A more elaborate overview of the variability of IRES is supplied in Appendix B.

3.1.3. *Predictability of IRES production*

IRES power production is predicted by meteorological models, which are not 100% accurate. Their RMSE forecast error is expressed as a percentage of the nameplate capacity. The error depends on the type of IRES, and is affected by the forecast horizon (it is harder to predict further into the future), and the size of the balancing region (spatial smoothing also reduces the forecast error) (Fig. 2).

The observed wind forecast error varies between countries. Day ahead RMSE forecast errors have been reported for Germany

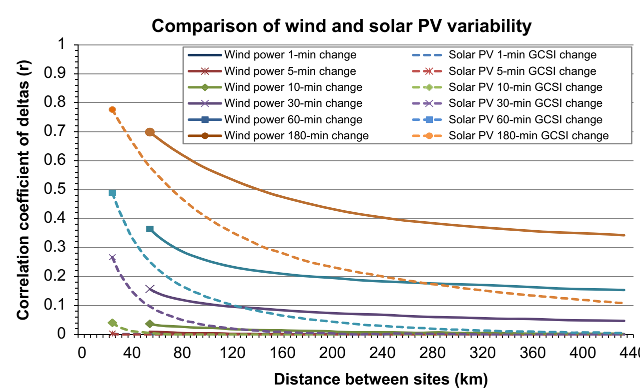


Fig. 3. Correlation coefficient between the changes in power output for wind power and GCSI for solar PV as a function of the distance between generators for different time intervals. Based on wind speed and insolation observations made by the U.S. in 2004, and published with kind permission from the authors [41]. Trends resemble those reported for Germany [11].

4.5–6.5 [42,43], Ireland (9.3%) [43], and West Denmark (8.9%) [11]. The day ahead RMSE forecast errors in US control areas ranged from 5% to 15% in 2009 [44].

The forecast error of solar PV is somewhat larger than that of wind power. The day ahead RMSE for the whole of Germany was 13% for solar PV [45]. For California, wind forecast errors were reported to be between 3.1% and 4%, depending on the season. For large-scale solar PV farms, they ranged from 2.3% to 6.9%, depending on the clarity of the sky [46].

3.1.4. *Observed impact on reserve sizes*

Limited data is available on the impact of wind power on the size of primary and secondary/tertiary reserves. In Europe, both reserve sizes have not increased with increasing wind penetration

levels in West Denmark, Germany, Spain, and Portugal [11,47]. However, in Denmark and Germany, the regular primary and secondary/tertiary reserves have been used more frequently [11]. Moreover, a special hourly wind power reserve of 150 MW with a 45-min deployment time has been instituted in one of the control areas in Germany [42], as well as a type of downward reserve in Ireland which has a size equal to the operating level minus the minimum load level of all online generators [47].

3.2. Increased reserve size—impact modeling

11 of the 17 integration studies looked at the extra non-event reserve sizes that are required if wind energy is introduced. These studies used four different approaches to quantify these reserves, which are explained in Appendix C. The primary reserves are discussed first, followed by the secondary/tertiary and hourly reserves.

3.2.1. Modeled size of primary reserves at seconds interval

Table 2 gives an overview of the increase in primary reserve size resulting from large-scale IRES penetration as calculated in five studies. Integration studies for mainland Europe are not included, because a pre-set reserve size of 3 GW is jointly supplied by all ENTSO-E members [32]. Fig. 4 shows the increase in total primary reserve size for all reported penetration levels in the studies.

As shown in Table 2 and Fig. 4, the calculated reserve sizes differ among studies, which can be explained by the different reserve sizing methodologies that have been used. The US-MIN and US-NY studies use the Stat-B-VAR approach. US-MIN assumes a wind variability of 2 MW per 100 MW of installed capacity and a non-event reserve size of 0.7% of peak load to balance load uncertainty. US-NY determines the variability based on historical measurements [28,30]. This results in a modest increase of 2–4% of the total second reserve capacity. This is in line with calculations in the US-EWITS study, which show that the impact of wind variability on the non-event reserve size is negligible, but that the forecast error is important.[3] The uncertainty surrounding the eventual wind power production is larger at 15 min to 1 h ahead of dispatch (when forecasts are made) than at the moment of dispatch. The larger degree of uncertainty requires a larger primary reserve size [13].

The US-SPP study uses the Stat-B-WLF approach based on the wind and load forecast errors. In addition, it accounts for indirect imbalances that arise from more variability in the system. The authors argue that more variability leads to a higher ramping duty for non-wind generators, which results in larger imbalances as it is harder for a generator to follow a variable generation schedule than a constant one. This effect is accounted for by multiplying the 95th percentile of the wind forecast error by a factor that measures the increase in non-wind variability resulting from variability of other sources. The study has established that this factor has a value between 1 and 2 for the study area, and uses a factor 2 in their calculations. As a result, the reported reserve sizes are about as large as the values reported by other studies for wind penetration levels that are twice as large [29]. No other literature mentions this extra multiplication factor.

A last set of studies uses dynamic reserve sizing based on the wind forecast error. The US-ERC study uses a combination of a basic and a dynamic approach, which calculates a custom non-event reserve size for every single hour. The average increase in total primary reserves is 2%, a low figure as a result of the large contingency reserves [10]. The same accounts for the US-WWSIS2 study, where the large contingency reserves dampen the increase in total primary reserves. Moreover, this study concludes that the effect of wind and solar PV on non-event reserves is very similar [15]. The IR-M study determines the primary reserves based on the second dynamic statistical approach, and the wind forecast error. The increase in size of the total primary reserve is somewhat higher than that of other studies. The higher wind penetration level and small size of the control area may be the cause of this, as well as the relatively small contingency reserves [7].

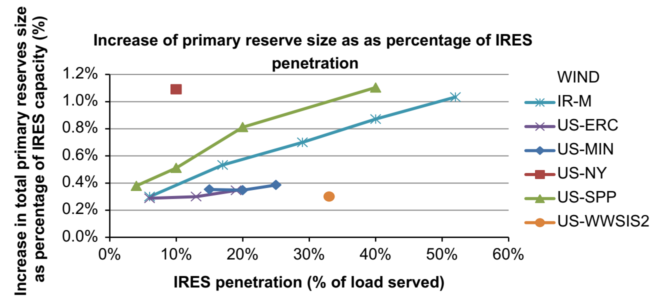


Fig. 4. Increase of total primary reserve size as a percentage of the IRES penetration level.

Overall, it can be concluded that, for penetration rates up to 30%, wind power will increase the size of the total primary reserves by 0.3–1.0% of the installed wind capacity. Reserves for solar PV could be somewhat larger, due to its lesser predictability (Section 3.1.3). The increase in reserve size becomes progressively larger at higher penetration levels. The reserves are mainly required to smooth out imbalances resulting from the wind forecast error. Contingency reserves constitute the largest share of primary reserves and are not affected by IRES generation, because the loss of power resulting from a single contingency at the largest power plant will likely remain larger than the loss resulting from a contingency at an IRES generation site.

3.2.2. Modeled size of secondary/tertiary and hourly reserves

An overview of the increase in secondary/tertiary and hourly reserve sizes is provided in Table 3 and Fig. 5. In Table 3, a number of properties are included that can affect the reserve size: the sizing methodology, the time horizon for which predictions are made (a longer horizon results in a larger forecast error, and thus requires more reserves) and the reliability requirement (if a higher percentage of the variability needs to be balanced by reserves, a larger reserve size is needed).

3.2.2.1. Secondary/tertiary reserves. The increase in secondary/tertiary reserve size has been determined separately by five studies. Two factors appear to affect the reserve size: the sizing approach and the balancing time frame. While larger reserves would be expected for larger balancing time frames, the US-WWSIS studies report relatively small reserve sizes. This is probably the result of using the IRES variability rather than the forecast error. This also applies to the small reserve size in the US-MIN study, even though the less efficient (i.e., overestimating) Stat-B sizing approach is used, which leads to higher system costs. Compared to these two studies, the reserve size of the IR-M study is relatively large.

The US-AR study reports a larger reserve size for solar PV than the other studies that model wind power. US-WWSIS2 concludes that solar PV requires a slightly smaller reserve size than wind power, because the uncertainty of solar PV is smaller (Fig. 5). Stoutenburg et al. conclude that reserves for wave power are akin to those for wind power [36]. The reserve size of solar PV is likely to be comparable to that of wind power, but both strongly depend on the forecast error.

[3] The US-EWITS study does not specify the primary reserve size used, and it is therefore not included in Table 2 and Fig. 4.

Table 2
Increase in average annual non-event and contingency primary reserves as reported by IRES integration studies for the highest IRES penetration scenario.

Study	**Power system details**				**Non-event primary reserve**				**Total primary reserve**			
	IRES penetration level (% of annual load)	IRES generation capacity (GW)	Total power production (TWh)	Total IRES power production (TWh)	Non-event reserve (MW)	Increase in non-event reserves caused by IRES wind penetration (%)	Reserve sizing method	Share of variations covered	Contingency reserve (MW)	Total primary reserves (MW)	Increase in total reserves for high-IRES case from low-IRES case (%)	Increase in total reserves for high-IRES case from low-IRES case as a percentage of IRES generation capacity (%)
		A **B**			**C** **D**	**=(D/C)−1**			**E** **F**	**G=C+E** **H=D+F**	**=(H/G)−1**	**=(H−G)/(B−A)×10^3**
Wind power												
IR-M	0%	0	53	6	n/a	n/a	Stat-D2-WLF	n/a	480[b]	640	**12%**	**1.0%**
	47%[a]	8	54	25	n/a				480[b]	717		
US-ERC	0%	0	n/a	0	233[c,d]	**22%**	Stat-B/D1-WLF	98.8%	2300[d]	2533	**2%**	**0.3%**
	19%	15	287	54	284[c,d]				2300[d]	2584		
US-MIN	1%	0.2	62	1	137[e]	**15%**	Stat-B-VAR	n/a	330[e]	467	**4%**	**0.3%**
	25%	6	85	21	157[e]				330[e]	487		
US-NY	0%	0	n/a	0	250[e]	**14%**	Stat-B-VAR	99.7%	1200[e]	1450	**2%**	**1.1%**
	10%[f]	3	n/a	9	286[e]				1200[e]	1486		
US-SPP	base (4%)	3	239	10	291[c,c,]	**35%**	Stat-B-WLF	90%	800[e]	1091	**9%**	**1.0%**
	20%	14	239	47	394[c,e]				800[e]	1194		
Wind + PV power												
US-WWSIS2	0%	0	760	0	1200[h]	**9%**	Stat-D1-WLF	95%	4200[h]	4200	**6%**	**0.3%**
	33%[g]	83.4	760	256	1300[h]				4200[h]	4456		

Reserve sizing method: Stat-B: basic statistical analysis, Stat-D1: first dynamic statistical approach, Stat-D2, second dynamic statistical approach. VAR: based on wind variability, WLF: based on wind and load forecast errors [Appendix C].

[a] Total electricity generation by IRES power amounts to 59% of the load served, but the reserve size has only been calculated for the inclusion of wind power.
[b] The Irish primary and secondary operating margins are the combined non-event and contingency reserves for a time frame of 1–90 s.
[c] The reserve size is the average of up and down reserves.
[d] The non-event and contingency reserves are called regulation and responsive service reserves, respectively, in the report. The study uses an approach which is a combination of a basic and a dynamic approach. It is basic in the sense that the reserve size is predefined based on historical wind and load data, but it is dynamic in that the reserve size is determined separately for every single hour in a year.
[e] The non-event and contingency reserves are called regulating and spinning reserves, respectively, in the report.
[f] The wind penetration level is 10% of the peak load.
[g] Total electricity generation by wind and solar PV power amounts to 16.5% of the load served each.
[h] The non-event and contingency reserves are called regulating and contingency reserves, respectively, in the report.

Table 3
Average annual secondary/tertiary and hourly reserve requirements as reported by wind integration studies for the highest considered IRES penetration level.

Study	Balancing timeframe	**Power system details**				**Non-event reserve**				
		IRES penetration level (% of annual load)	IRES capacity (GW)	Total power production (TWh)	Total IRES power production (TWh)	Non-event reserve (MW)	Increase in non-event reserve for high-IRES case from low-IRES case (%)	Increase in reserve for high-IRES case from low-IRES case as percentage of IRES generation capacity (%)	Reserve sizing method	Forecast horizon, Share of variations covered
			A **B**			**C** **D**	$=(D/C)-1$	$=(D-C)/((B-A)\times 10^3)$		
Wind Power										
GER-D1[a]	15 min to 4 h	5% 14%	14.5 35.9	524 552	24 77	697 2422	247%	**8%**	Stat-D2-WLF	1d, 99.9%
GER-D1[a]	15 min to 4 h	5% 14%	14.5 35.9	524 552	24 77	160 451	182%	**1.4%**	Utilized	n/a, n/a
GER-F[b]	15 min to 4 h	n/a 23%	n/a 48	n/a 513	n/a 118	n/a n/a		**21%**[j]	Stat-B-WLF	1d, n/a
GER-F[b]	15 min to 4 h	n/a 23%	n/a 48	n/a 513	n/a 118	n/a n/a		**5%**[j]	Utilized	n/a, n/a
IR-M[c]	1.5–5 min	0% 47%	0 8	53 54	0 25	408 632	55%	**3%**	Stat-D2-WLF	n/a, n/a
UK-S	30 min to 4 h	n/a 20%	n/a 25	n/a 400	n/a 80	n/a 5470		**21%**[j]	Stat-B-WLF	4 h, 99.7%
US-EWITS[d]	Minutes and hours	0% 20%	n/a 226	n/a 3725	n/a 745	n/a 39,584	Dynamic	**18%**[j]	Stat-D1-WLF	1 h, 99.7%
US-MIN[e]	Minutes	1% 25%	n/a 6.1	62 85.1	1 21	100 124	24%	**0%**	Stat-B-VAR	n/a, 95%
US-MIN[e]	Hour	1% 25%	n/a 6.1	62 85.1	1 21	152 538	254%	**6%**	Stat-B-WLF	1 h, 95%
US-SPP[f]	10 min to 4 h	0% 40%	n/a 25	n/a 287	n/a 85	1272 4314	239%	**12%**	Stat-B-WLF	4 h,95%
Wind and Solar PV/Wave power										
IR-M[c]	5 min to 36 h	0% 59%	0 10	53 54	0 32	418 1313	214%	**9%**[k]	Stoch-WLF	1d, 90%
US-WWSIS1[g]	10–60 min	0% 35%	 36	 286	 100	425 850	1.1% load+ 5% wind	**1%**	Stat-D1-VAR	n/a, 95%
US-WWSIS2[h]	5–60 min	0% 35%	0 83	760 760	0 256	n/a 3482		**4%**	Stat-D1-VAR	1 h, 70%
Solar PV										
US-AR[i]	10 min	0% 8%	0 2	46 46	0 256	n/a 84		**5%**	Stat-n/a-WLF	1 h, 99%

Sizing methodology abbreviations: Stat-B: basic statistical sizing approach. Stat D1/D2, dynamic statistical sizing approach 1/2. Stoch: stochastic sizing approach. Utilized: utilized reserves. VAR: size is based on the variability of wind. WLF: size is based on the wind and load forecast errors. See Appendix C for explanation.

[a] The reserves are called Regel- und Reserveleistung in the report. The quantities are the average annual increase from a situation without wind. The average of positive and negative reserves is shown.

[b] The reserves are called Regelleistung in the report. The quantities are the average annual increase from a situation without wind. The reported size is the average of positive and negative reserves, based on a forecast error of 5.3% RMSE.

[c] The secondary/tertiary reserve and hourly reserve are called Tertiary operating reserve band1(with an activation time between 90 s and 5 min.) and replacement reserves (with activation times from 5 min to 36 h), respectively, in the report. Average yearly reserve sizes are used for both reserves. Total electricity generation by renewable sources amounts to 59% of the load served, and is only considered with the replacement reserves.

[d] The reserve consists of the additional reserves and next-hour wind forecast error regulation reserves from the report, the time frames of which are not specified in the report. The size is variable and decreases for lower load factors, as displayed in Figs. 5–9 of the US-EWITS report. The average size is only provided as an aggregate figure together with the regulation reserve. It is assumed that the "next-hour wind forecast error regulation reserve" is 60% of the total spinning reserves, based on the ratio from Tables 5 and 6 of the report. Separate contingency reserves are defined in the study.

[e] The secondary/tertiary reserve and hourly reserve are called non-spinning reserve and load-following reserve, respectively, in the report, the time frames of which are not specified.

[f] The reserve is called load-following reserve in the report. This reserve does not exist yet, but the study recommends that it be instituted. The authors also propose a minute-reserve to be instituted, but they do not provide information on this reserve. The reserve size is calculated based on the standard deviations of load and wind forecasts, which are combined as independent variables.

[g] The reserve is called variability reserve in the report, and the size is based on the in-area scenario. IRES penetration consists of 30% wind power and 5% solar PV power. The reserve quantities are based on a paper by Milligan [31]. The reserves are defined as a percentage of the load and forecasted wind power.

[h] The reserves are called flexibility reserves in the report. The values show the largest reserve size required.

[i] The reserves are called operating reserves in the report. The values for 99% reliability are shown.

[j] In these studies the non-event reserve of the reference case was not quantified (element "C" in the table), which results in a relatively larger increase in reserve size.

[k] The hourly reserves seem to decrease at a penetration level of 59%, which is the result of the inclusion of 1.4 GW of wave power, which is modeled as "must-take" generation without a reserve requirement. If only wind power is considered, the reserve size increases to 14% of installed wind capacity.

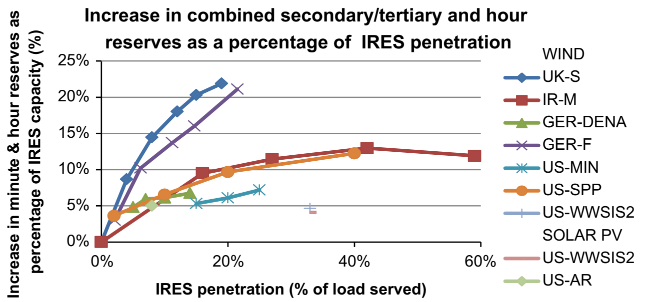


Fig. 5. Increase in combined secondary/tertiary and hourly reserves as a percentage of installed IRES capacity. If no reserve size is defined for 0% wind penetration, it is extrapolated from the other reported reserve sizes.

3.2.2.2. Hourly reserves. The size of hourly reserves has been determined by the US-MIN and IR-M studies to be 6% and 9% of the installed wind capacity at a wind penetration of about 25% [7,28]. This is significantly more than the combined secondary and tertiary reserve sizes. The difference in size can be explained by the longer balancing time frame and associated forecast horizon as well as the sizing methodology.

3.2.2.3. Combined secondary/tertiary and hourly reserves. The increase in reserve size of secondary/tertiary and hourly reserves combined is likely to be around 6–11% of the installed IRES capacity at a wind penetration of 20% (Fig. 5). Differences in the reported reserve size can be attributed to a number of factors. The values from UK-S and GER-F are higher, because they do not supply the reserve size for the reference case. The UK-S, US-SPP, and GER-F studies use the Stat-B-Var approach, whereas the US-MIN study is also partly based on the Stat-B-WLF approach. Differences also exist in the forecast horizon, the share of the imbalances that are covered and the geography of the study areas. The studies with more advanced sizing approaches (i.e., not Stat-B) report an increase of 6–11% at 20% wind penetration, which is a range that was also reported in a review of studies before 2006 [16].

A number of trends can be observed from Table 3 and Fig. 5:

(1) All studies show that the relative reserve size will increase at higher IRES penetrations. The curves show a steep increase at lower penetration rates, which gradually levels off.
(2) The sizes of both reserves are larger than the primary reserves, which have a size of 0.3–1.1% of installed wind capacity. This is caused by the larger correlation in power production at longer timeframes, which results in larger forecast errors.
(3) The amount of reserves that will actually be used is much smaller, as reported by the GER-F and GER-D1 studies: around 20–25% of the total available reserves.
(4) Differences exist between the reported reserve sizes, which can be explained in general terms by the sizing methodology and regional differences. It is difficult to identify strict causal relations, as explained in Section 5.
(5) The reserve sizes for different IRES types appear similar, and are dependent on the forecast error.

The increased reserves are provided by thermal capacity, requiring more available capacity for reserve provision, whilst decreasing the operating range that is available for power production. The effect on the dispatch of power plants is not quantified, but the increase in reserve size is in the order of 1–11% of peak load, which suggests that power plants may be affected.

A number of observations related to reserve sizes are made in the studies. The importance of demand side management (DSM) in correcting imbalances is mentioned by UK-S and US-WWSIS1, thus reducing the need for reserves [12,26]. Some studies have differentiated between upward and downward reserves [8,29]. It remains unclear whether this is necessary when investigating the effects of wind power. Downward reserves especially will be used more frequently compared to today's systems, but as the US-WWSIS1 study suggests, these can also be realized by curtailing excess wind production [12].

3.2.3. How to model reserves

We find that the results and recommendations from IRES integration studies draw a consistent picture of how the reserve sizes can be determined. The sizes of the reserves in a UCED model are determined exogenously in a deterministic way (e.g., [12,13]) or in a stochastic way [48]. These reserves are set as a constraint in this model (i.e., the minimum capacity that has to be available within a time step).

The size is based on the required reliability of the power system, the historical IRES power production patterns and their associated forecast errors, as well as the historical load pattern and its associated forecast error, as described in Section 3.1. Historical wind production patterns should have the same time step as the balancing time frame and have the same spatial spread as the locations of wind farms [18], as used in wind integration studies, e.g. [12–14].

The UCED model should have a time step equal to or smaller than 1 h, as the largest reserves are required at this timescale. Reserve capacity constraints for faster reserves can be applied with a time step of 1 h, because wind conditions do not change substantially within 1 h; hence the reserves sizes do not change much either (Appendix B). The results from wind integration studies suggest that it is probably sufficient to only include the reserves with longer balancing time frames (> 10 min), as wind power production among different sites starts to correlate more strongly—necessitating larger reserve sizes. Moreover, the flexibility constraints of power plants should be included to determine the reserve capacity supplied per unit per time step.

Furthermore, a number of specific improvements have been suggested, which may be implemented when performing an in-depth study into system reserves. Such a study could focus on specific reserve-related aspects, rather than on accounting for system reserves as part of a more general power system study.

- A smaller time step can be used for the power system model to study the demand for reserve capacity at short balancing time frames in more detail [13].
- To determine the reliability of a future power system, the uncertainty of wind and load forecasts, as well as plant availability need to be modeled stochastically rather than deterministically [49].
- Currently, only the reserve capacity size is determined, not the dispatch of reserves. The actual reserve dispatch can be simulated by basing unit commitment on forecasted wind production and load patterns, and unit dispatch on the actual patterns. Only a limited share of reserve capacity has been simulated to be actually utilized [8,22].

Based on the following facts, we deduce that the above-mentioned way of modeling is a sufficiently accurate representation:

- The starting points of these analyses and present-day practices of grid operators are the same. Both aim for a predefined level of reliability (e.g., an LOLP of 0.1 day/year) that is challenged by uncertainties regarding the load, IRES power production and availability of power plants. Currently, reserve sizes are still based on empiric definitions, but ENTSO-E also allows a reserve sizing methodology that is based on a predefined system reliability for secondary reserves [32,33].

- The way in which the uncertainty of wind power is treated in this methodology corresponds to current practices of TSOs [50,51]. Forecasts are used as a proxy of the wind power production.
- The calculated reserve sizes are in line with the properties of wind power. At short time frames (< 5 min), the reserve size is about three times the 1-min variability (σ=0.3% of nameplate capacity; Appendix B). This is large enough to cover 99.7% of all variability. At longer timeframes and at larger penetrations, the reserve size increases because power production becomes more correlated.

3.2.4. How to model reserves in a low-carbon power system

The current reserve modeling approach will be largely sufficient to model reserves for future low-carbon power systems. For such systems, however, the current approach does have a number of limitations:

- The specific reserve size per GW of installed wind capacity increases for higher penetration levels (Fig. 5), resulting in very sizable reserves. It is therefore important to use an efficient sizing methodology. Based on the literature and the outcomes of wind integration studies, the dynamic statistical and stochastic approaches are recommended [52]. It has been reported that stochastic sizing can reduce the size of reserves whilst maintaining the same level of system reliability [53].
- The market design of the power system and associated reserve markets also influences the size of reserves. If the system includes frequent updating of the wind forecasts, this will decrease the size of the reserves, because the time horizons will become progressively shorter and forecasts therefore more accurate [7,53]. Moreover, wind turbines are currently not allowed to provide (downward) reserves, because these are traditionally supplied by non-intermittent generators. As newer types of wind turbines are technically capable of providing reserves, they may do so in a future power system [54].
- The provision of reserves could become an issue in a low-carbon power system, as IRES require flexibility to balance their forecast errors, while low-carbon generators are currently relatively inflexible [4,5]. Moreover, situations with high IRES power production will result in the commitment of a smaller number of thermal units, which will have to provide a relatively large amount of reserves. It is therefore important to include constraints on the operational flexibility of thermal power plants, which could affect both regular power production as well as the supply of reserves.
- Interconnection capacity can reduce the reserve size by sharing reserves among control areas [18,55]: reserve sharing within the ENTSO-E synchronous area could reduce the overall reserve size by 35–40% [17].
- Demand-side management can decrease imbalances, thus reducing the need for reserves [12,26].
- With larger reserve sizes, it may be necessary to model the actual dispatch of reserves instead of only reserve capacity. This will account for fuel use and CO_2 emissions resulting from reserve provision.

3.3. Curtailment of IRES production

3.3.1. Mechanism behind IRES curtailment

IRES integration studies show that IRES curtailment can be caused by both insufficient transmission capacity and surplus IRES production. When the total generation of essential capacity (i.e., must-run or reserve-supplying capacity) exceeds the residual load (which equals load—IRES power production), IRES production is curtailed. Curtailment is expressed as the percentage of total potential wind generation.

3.3.2. Observed IRES curtailment

Historical wind curtailment has been influenced by the availability of transmission and interconnection capacity. In mainland Europe, insufficient transmission capacity caused hardly any

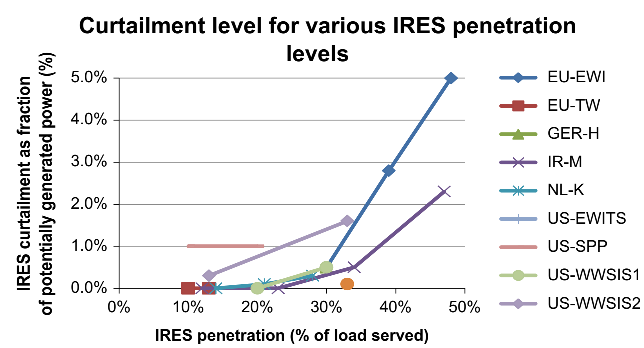


Fig. 6. Curtailment levels as a function of the IRES penetration level. The US-EWITS study is left out to improve visibility of the other studies' results.

Table 4
Curtailment levels as reported by wind integration studies.

Study	IRES penetration (% of annual load)	Curtailment [curtailed IRES production (TWh yr^{-1})/total IRES production (TWh yr^{-1})] (%)	Transmission constraints within national grids	Interconnection with neighboring countries
EU-EWI	30/39/48[b]	0.5/2.8/5[a,b]	No	Yes
EU-TW	16–18.5	< 0.1	No	Yes
GER-H	50	0.6/0.8[c]	No	No
IR-M	27/42/59[b]	0/0.5/2.4[b]	No	Limited (only Great Britain)
NL-K	28	0.3	No	Yes
NL-U[d]	33	0.1	No	Yes
US-EWITS	20/30[b]	3.5–7/9.6[b]	Yes	n/a
US-SPP	10/20[b]	1/1[b]	Yes	Yes
US-WWIS1	23/35[b]	0/0.9[b,e]	Yes	Yes
US-WWIS2	13/33	0.3/1.6[b,e]	No[f]	Yes[f]

[a] 6–10% of these curtailment levels are solar PV power curtailment, the remainder is wind power curtailment.
[b] Curtailment levels for the respective wind penetration levels.
[c] Curtailment levels for a scenario with and without retirement of nuclear plants, respectively.
[d] Based on the scenario with a 1 h market gate closure, and international exchange.
[e] Curtailment is not specified per IRES generator type.
[f] Transmission grid constraints between US states are included. Major load centers are separately included in California.

curtailment: 0% in Denmark and 0.2–0.4% in Germany in 2010 [56,57]. European countries with limited interconnections also experienced more situation of surplus wind production: 1.2% in Italy, 0.5% in Spain, and 2.1% in Ireland in 2012 [56].

In the United States, the average curtailment level has been 5% between 2008 and 2010, primarily due to insufficient transmission capacity [58]. Only isolated areas (Hawaii) and operators with large shares of hydro power (BPA) encountered surplus wind production [56]. More transmission capacity and better market integration of wind power have lowered curtailment since then [56].

3.3.3. *Modeled IRES curtailment*

Table 4 and Fig. 6 show modeled curtailment levels and whether or not they account for national transmission constraints and interconnectors.

Two mechanisms affect curtailment levels. First, transmission constraints are an important cause, and studies without them show lower curtailment levels. Without this constraint, US-EWITS curtailment levels decreased from 6.4% to 0.1%. US-SPP, US-WWSIS1, and US-EWITS assert that transmission constraints will remain an important cause of curtailment [12,29].

Second, curtailment occurs during hours of oversupply of IRES generation. Exporting power during these hours to neighboring regions through interconnectors decreases curtailment. Because the correlation in IRES power production decreases over distance (Fig. 3), neighboring regions may not encounter oversupply simultaneously. Both IR-M and GER-H have limited or no interconnection capacity and both show relatively high curtailment levels. Removal of all interconnection capacity increases curtailment levels to 16% in NL-U [7,14,24]. Conversely, high IRES penetration levels may increase curtailment levels, because they exacerbate the oversupply of wind power, as shown by the high curtailment levels for higher penetration levels by EU-EWI and IR-M [7].

Moreover, limited flexibility of the generation portfolio can increase the amount of essential capacity, because more capacity is needed to supply reserves. As a result, the (curtailment of the) oversupply of wind power increases. The NL-K and US-WWSIS1 studies forecast 2–5 times higher curtailment if the flexibility of CHP (NL-K) and coal power plants (US-WWSIS1) decreases.

Wind power appears to be curtailed mostly because it also generates power during hours of low load, whereas solar PV power production occurs during the middle of the day [20]. Combining these two IRES reduces the overall curtailment [15].

3.3.4. *How to model IRES curtailment*

To quantify curtailment, the two main mechanisms, as well as flexibility constraints, can be modeled. A time step of 1 h is commonly used, and has been reported to be sufficiently small [59]. To quantify the prime cause of curtailment, transmission constraints, and a regional power flow model is required, which is (computationally) complex. It therefore depends on the focus of the analysis if this cause of curtailment should be quantified.

To quantify curtailment resulting from oversupply of wind power, the residual load is compared to the essential online capacity for every time step. This capacity is determined by the power plants that need to be online to deliver reserve capacity, the must-run capacity, and the capacity needed to be online to meet electricity demand in subsequent hours. Whenever the minimum generation exceeds the residual load, and this power cannot be used elsewhere (e.g., interconnections, electricity storage), curtailment occurs. Moreover, it is important to model interconnectors with neighboring countries and DSM, as these may reduce the curtailment levels (Section 3.3.2).

We conclude that this recommended modeling approach is accurate, because the simulated mechanisms are the same as those that have been reported to be responsible for curtailment in practice and in integration studies [11,47,52]. Moreover, the modeled wind curtailment values are comparable in size to historic values.

3.3.5. *How to model IRES curtailment in a low-carbon power system*

In addition to the recommendations above, it is important to include two more factors. Firstly, the flexibility of thermal generators could cause curtailment, because reduced flexibility of base-load generators may result in more curtailment, as shown for nuclear [24] and coal-fired generators [12]. Secondly, an efficient reserve sizing methodology can reduce the amount of reserves required, which can reduce the amount of essential capacity, and subsequently lower the curtailment caused by oversupply of wind power [29].

3.4. *Increased specific emissions of thermal generators*

3.4.1. *Mechanism behind increased specific emissions*

With increasing wind power penetration, operation of thermal power plants will have to become more flexible to balance the variability in residual demand, and deal with the uncertainty of wind forecast errors. As a result, power plants will have to ramp up more often, run more part-load, and need to start up and shut down more often, which will all lead to increased fuel consumption. This will increase the specific CO_2 emissions (in kg CO_2 kWh^{-1}), which are defined as the percentage by which the average specific CO_2

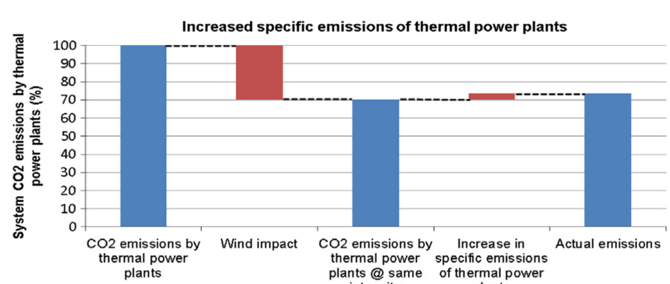


Fig. 7. Schematic representation of the increased specific emissions of thermal capacity.

Table 5
Reported increase in specific CO_2 emissions of thermal generators resulting from IRES.

Study	Region	IRES penetration (% of annual load)	Average increase in specific CO_2 emissions of thermal generators (%)[a]	Considered efficiency decreasing effects
EGER-W	East Germany	11	7	Part load efficiency, start-stop
GER-F	Germany	23/35[b]	8.3/5.5[b]	Part load efficiency, start-stop
US-WWSIS1[c]	Western US States	23	2.3	Part load efficiency, start-stop, ramping
US-WWSIS2	US- WesternInterconnection	33	$<1\%$	Part load efficiency, start-stop

[a] See Fig. 7 for definition.
[b] Wind penetration and efficiency reductions for 2020 and 2030, respectively.
[c] As reported in a later publication by the original study's authors [62].

emissions of fossil power production are increased in a system with IRES, compared to a system without IRES (Fig. 7).

3.4.2. *Observed increased specific emissions*

Limited observations are available: only the increase in specific emissions has been estimated to be 0.8% in Great Britain in 2011 [60]. In Spain, delivery of auxiliary reserves increased specific emission by 0.02% in 2011 [61].

3.4.3. *Modeled increased specific emissions*

Five studies quantified the increase in specific emissions caused by IRES (Table 5). Only the US-WWSIS1 study included the effect of ramping, which was judged to be insignificant [8,15,62].

Overall, the specific emissions increase by up to 8.3% at 20% IRES penetration, which is comparable to the ~0–7% range reported by studies from before 2005 [16]. The actual increase depends on the composition of the generation mix. GER-F reports a lower increase in specific emissions for a higher IRES penetration in 2030, because flexible natural gas and coal capacity replaces inflexible brown coal-fired generation.

3.4.4. *How to model increased specific emissions*

Two elements primarily determine the increase in specific emissions: higher variability in residual demand and its effect on thermal generators. Modeling residual demand is a basic element of a wind integration study, which is ideally based on historical wind and load patterns with a resolution of <1 h [18]. For thermal generators, the flexibility constraints need to be included, besides parameters that describe the extra CO_2 emissions associated with start-stop events, part load operation, and, optionally, ramping events. These events occur at multi-hour timescales, so this analysis can be performed with a time step of 1 h, like the studies in Table 5. Only when considering the effects of ramping, a shorter time step may be required.

An in-depth study may require the inclusion of a number of indirect factors. Firstly, the specific emissions could be affected by interconnections and grid constraints. Interconnections can allow for a smoother operation and higher load levels of power plants. Grid constraints can lead to suboptimal dispatch of power plants. Secondly, the reserve size can affect the extent to which thermal generators have to run at part-load to supply sufficient up-reserves. Thirdly, uncertainty in wind forecasts can lead to suboptimal unit commitment and dispatch [53], which affects the specific emissions. A model that accounts for uncertainties in wind power production is therefore recommended.

We conclude that this recommended modeling approach is sufficient to accurately model the efficiency reduction of thermal generators for present-day and future low-carbon systems,

Table 6
Displaced coal and natural gas-fired capacity at high wind penetration for different studies.

Study	Wind penetration (% of annual load)	Generation capacity per fuel as % of generation park		Capacity based on (Capacity development[k])	Reduction of generation per fuel type as % of reference case generation	
Multiple cases		Coal (%)	Natural Gas (%)		Coal (%)	Natural Gas (%)
EU-EWI[a]	30	10	19	Simulations, cases	23	24
	39	8	17		31	48
	48	6	16		46	65
IR-M[b]	23	18	44	Simulations, cases	6	22
	34	18	37		20	34
	47	18	25		83	34
NL-K[c]	14	14	64	Historic (Coal, NG↑)	−68	44
	21	14	64		−51	49
	28	14	64		−36	52
NL-U[d]	14	31	46	Simulations, ref	11	32
	32	31	46		29	47
US-EWITS[e]	20	66	6	Near future, ref (Coal↑)	21	23
	30	66	6		34	27
US-WWSIS1[f]	20	45	43	Simulations, ref	1	31
	30	45	43		7	57
US-WWSIS2[g]	13	n/a	n/a	Simulations, ref	2	27
	30	n/a	n/a		23	70
Single case						
EU-TW[h]	13	10	26	Simulations, case	6	−38
GER-D2[i]	27	13	11	Simulations, case	27	33
US-SPP[j]	20	40	42	Historic	12	53

[a] The Scenario A 2020 case is used as the reference.
[b] The modeled 12% wind scenario in 2020 is used as reference, and compared respectively to the P2, P5, and P6 scenarios.
[c] Capacities are historical capacities from 2009. The historical situation in 2009 is used as a reference, to which the scenarios of 2020 are compared. A negative reduction is an increase.
[d] The modeled situation of 2014 with 0% wind penetration is used as reference, and compared to situations with 14% and 32% wind penetration. No international exchange is assumed.
[e] The capacities are historical capacities from 2010, corrected for planned construction and decommissioning. The reference scenario with 6% wind penetration is used as reference, and compared to the scenarios for 2024. The average of the 2004 and 2005 wind profiles scenarios is used.
[f] The simulated future no-wind scenario is used as reference, and compared to the modeled scenarios for the whole WECC area.
[g] The NoRenew scenario is used as the reference, to which the HiMix scenario is compared.
[h] The modeled 2020 simulation with 10% wind is used as reference, and compared to the 2030 simulation with 12% wind. A negative reduction is an increase. Developments from 2020 to 2030 include a decrease in coal capacity and an increase in natural gas capacity.
[i] The historical 2005 production and capacities are used as reference, to which the modeled 2020 production is compared.
[j] The 2009 base case with 4% wind penetration is used as reference, to which simulated scenarios are compared.
[k] The provided capacities can be historical capacities or simulated capacities for either the reference case or the actual scenarios. If historical capacities have developed towards a particular type of generation capacity, this is shown.

because the direct mechanisms that are simulated are the same as those that have been reported to be responsible for curtailment in practice and in integration studies (Table 5).

3.5. Displacement of thermal generators

3.5.1. Mechanism behind the displacement of thermal generators

When the share of IRES production increases, the shares of other generators are reduced. This displacement primarily depends on the merit order: the most expensive, often thermal, generators are displaced first. In addition, the operating hours of inflexible units can be reduced when the system requires flexibility to balance IRES power production.

3.5.2. Observed displacement of thermal generators

In Europe, a combination of low coal prices and large shares of wind and solar PV power has displaced a large share of natural gas-fired power plants (e.g., a 27% reduction in 2012 in Germany [63]). Although it is hard to quantify the exact roles of these two aspects in the displacement, they have made power generation from natural gas unprofitable in countries such as Spain and The Netherlands, and caused power plant closures in Germany and France [64].

3.5.3. Modeled displacement of thermal generators

Natural gas-fired capacity is mostly displaced through “merit order displacement” (Table 6). At higher wind penetration levels, coal capacity is displaced too, by “deeper” displacements in the merit order, e.g., during the night. The initial generator mix also affects displacement: if the mix contains a high share of coal capacity, more coal capacity is displaced, as shown in US-EWITS. Nuclear, lignite, and hydro capacities make up large shares in some of the studied areas, but their utilization does not change.

The merit order, and hence the displacement of capacity, can be affected by two factors. First of all, changes in fuel and CO_2 prices can lead to a switch of coal and natural gas capacity in the merit order, leading to the displacement of coal capacity. This is shown in IR-M for high wind penetrations, which coincides with high carbon prices (€80 t^{-1}), and sensitivity analyses of US-WWSIS1 and US-EWITS with reduced natural gas prices. Secondly, changes in the installed generation capacity can affect the merit order, as shown by NL-K and EU-TW.

A higher demand for flexibility could lead to the displacement of inflexible capacity (“inflexibility displacement”). US-SPP suggests that flexibility may be important for the provision of reserves; and a less flexible generator mix led to more coal and less natural gas capacity being displaced in NL-K. On the other hand, IR-M concludes that less-flexible generator mixes are still sufficiently flexible. Higher minimum load levels for coal-fired capacity did not affect power system operation in US-EWITS.

US-WWSIS2 shows that the IRES type has a slight impact on displacement. Higher shares of solar PV result in less displacement of coal capacity, potentially as a result of less “deep” displacement during the night. Instead, NGCC capacity is displaced.

Displacement may fundamentally affect power system operation. All studies report a reduction in both total power system CO_2 emissions and lower load factors of individual power plants. For Great Britain, for example, load factors of both coal and natural gas capacities were forecasted to decrease markedly from 50% to 60% to about 30% for coal, and from 70% to about 35% for new gas capacity between 2010 and 2030 [65]. EU-EWI, NL-K, and NL-U also observe that the addition of wind will negatively influence the profitability of existing and new power plants, especially those designed for base-load operation.

3.5.4. How to model displacement of thermal generators

The results suggest that it is sufficient for present-day power systems to only model merit order displacement. This is carried out with a UCED model that accounts for all variable costs associated with power production. Lastly, carrying out a sensitivity analysis for factors that affect the merit order, such as fuel and CO_2 prices, is recommended.

In low-carbon power systems, inflexibility displacement could also occur. To model this type of displacement, the flexibility limitations of the generator should be modeled with constraints, especially ramping speeds and start-up times [7]. In addition, wind power production patterns should be modeled with sufficient detail to determine their variability. This requires a time step of at least 1 h, but shorter time steps may be required for fast ramping events to assess whether the committed capacity is sufficiently flexible.

Moreover, interconnections may also influence displacement across control area boundaries. NL-U and IR-M report that high wind penetration may displace capacity in neighboring countries. This is in line with current observations: Denmark has a high wind penetration, and exports wind power to neighboring countries [66]. Grid constraints can hamper international power exchange, and can result in suboptimal dispatch, as shown by US-SPP.

3.6. IRES contribution to resource adequacy

3.6.1. Mechanism behind the IRES contribution to resource adequacy

The ability of the power system to have enough capacity to meet demand is called the resource adequacy. It is quantified as the surplus available generation capacity during peak load hours, as a percentage of peak load.[4] This percentage should be adequate to ensure a reliable power supply (at least ~15% in the U.S., and 15–23% in Europe) [67,68].

Two methods are used to determine the contribution of IRES to the resource adequacy. Firstly, power system reliability metrics are used. The contribution of IRES is quantified as the amount of extra load that can be accommodated in a system with IRES as compared to a system without IRES, whilst maintaining the same power system reliability (expressed as the LOLP or LOLE). This amount is called the effective load carrying capacity (ELCC), defined in MW.

Secondly, the contribution of IRES is measured by calculating the amount of “perfect capacity” that is substituted by adding the IRES capacity to the system whilst maintaining the same system reliability. Perfect capacity is a hypothetical generator without downtime. This definition accounts for transmission constraints within a synchronous area, and is 90–95% of the ELCC value [12].

To compare the contribution of IRES between power systems, the ELCC or perfect capacity is often expressed as a percentage of the nameplate IRES capacity, called the capacity credit (or capacity value). The capacity credit is region-specific, and depends on the IRES penetration [11,69].

3.6.2. Observed IRES contribution to resource adequacy

In Europe, the TSOs decide how they determine the capacity credit of IRES power, the results of which are not communicated. In the U.S., TSOs decide how they determine the capacity credit. The values they use range between 9% and 20% [70].

3.6.3. Modeled IRES contribution to resource adequacy

In Table 7, an overview is given of the reported IRES capacity credit values. These have been calculated through a statistical analysis or with a power system reliability model based on extrapolated historical wind and load data. A system reliability model determines the ability of the power system to satisfy electricity demand at all times. This can be carried out by means of a probabilistic analysis based on the availability of thermal and

[4] NERC uses the annual peak load and ENTSO-E uses the load at two reference points in the year in their methodology to calculate the resource adequacy.

Table 7
Reported capacity credit values.

Study	IRES penetration (% of annual load)	Wind capacity credit (% of nameplate capacity)	Solar PV capacity credit (% of nameplate capacity)	Calculation methodology	Type of capacity credit	Reliability requirement (LOLE/LOLP)
EU-TW	10 (no exchange) 10 (exchange)	8 14		Statistical	ELCC	LOLP: 1%
GER-D1	3 4 9 13	19 13 8 6		CREDIT-WEA	ELCC	LOLP: 1%
UK-S	4 8 12 15 19	34 30 26 23 20		Statistical[a]	ELCC	LOLP: 9%
US-EWITS	20 (no exchange) 20 (exchange) 30 (no exchange) 30 (exchange)	14–18[b] 24–28[b] 16[c] 25[c]		GE MARS	ELCC	LOLE: 0.1 d/yr
US-MIN	15 20 25	4.5[c] 5.1[c] 4.1[c]		GE MARS	ELCC	LOLE: 0.1 d/yr
US-NY	[d]	10		GE MARS	PCR	LOLE: 0.1 d/yr
US-WWSIS1	11 22 33	11 11 11	29 27 27	GE MARS	PCR	LOLE: 0.1 d/yr[e]

[a] The method is specified, but the capacity credit seems to be based on a statistical analysis.
[b] The lowest capacity credit for the years 2004–2006 is reported, as this is the ELCC on which the power plant portfolio needs to be dimensioned. The range indicates the credit values for different wind power siting scenarios, of which scenario 2 is depicted in the figure.
[c] The lowest capacity credit for the years 2004–2006 is reported, as this is the ELCC on which the power plant portfolio needs to be dimensioned.
[d] Wind power provides 10% of the peak load.
[e] No LOLE was mentioned, but the paper states that 0.1d-yr is a common target

IRES capacity (CREDIT-WEA) or a Monte-Carlo analysis of a power system simulation model that accounts for the availability of generators (GE MARS).

At a 10% IRES penetration level, capacity credit values range from 8% to 28%. The high capacity credit values of UK-S could be explained by the lower reliability requirement, but the other differences do not seem to be caused by different methodologies. Although the studies consider either ELCC or PCR types of capacity credit, the difference between these metrics is smaller than the observed differences [12].

The reported capacity credits are generally lower than the capacity credit values reported in studies from before 2005, most of which report capacity credits > 15% at 10% wind penetration [16]. It is unclear what causes this difference. The calculation methodology might play a role: older studies sometimes only consider peak hours, or use a time step larger than 1 h, which will result in an overestimation of the capacity credit [69].

US-WWSIS1 reports that the capacity credit of solar PV is 2.5 times that of wind power. This is due to a better match between the production pattern of solar PV and the load pattern.

A number of factors influence the capacity credit:

- A high correlation in IRES power generation reduces the capacity credit. At higher correlations, the generation patterns resemble each other more, increasing the chance that little or no power is produced at a time of high electricity demand. Two trends increase the correlation: (1) higher wind penetration, as shown in Fig. 8, and (2) a smaller diversity in wind locations. In US-EWITS, three siting layouts were considered for the 20% penetration. The more the wind installed at remote locations (offshore power in the case of US-EWITS), the higher the capacity credit becomes. The difference is a 1–9% increase in the relative capacity credit, depending on the year [13]. Related to these two factors, the capacity credit has been reported by EU-T to increase strongly if it is calculated for an aggregated, interconnected area, such as Europe. This would also explain why other studies of large areas, the US-EWITS and US-WWSIS1, also report relatively high capacity credits.
- The variation in yearly weather. The results of US-MIN and US-EWITS for the years 2004, 2005, and 2006 show a spread of up to 5% points. As the capacity credit is an indicator of the amount of capacity which can be relied on for a given reliability target, the smallest value determines the capacity credit. For an accurate quantification of the capacity credit, it is therefore also important to analyze multiple years.

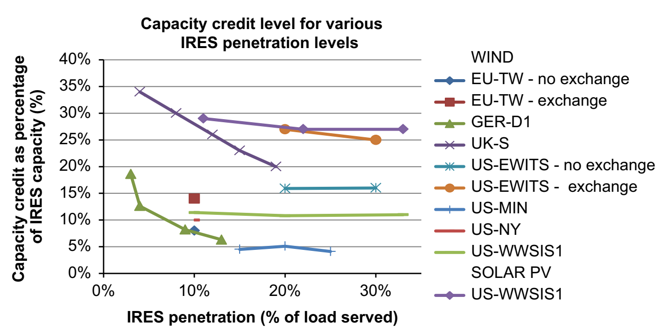


Fig. 8. Capacity credits for different wind penetration levels as reported by wind integration studies.

3.6.4. How to model the resource adequacy of wind power

A task force of the IEEE Power and Energy Society recently suggested a preferred methodology to determine the capacity credit. First of all, the LOLE of a power system without wind is calculated with a power system reliability model at an hourly resolution. Next, wind power is treated as negative load, and the

new LOLE is calculated. Then, the load data is universally increased with a delta-load, and the LOLE is calculated. This last step is performed in an iterative way, in which the delta-load is increased until the LOLE matches that of the system without wind power. This delta-load is the ELCC of the wind power [71].

This approach can also be applied for solar PV and wave power. It requires data on the (scheduled) outages of power plants in the system, as well as load and IRES power time series. It is important to use IRES and load patterns that span the same time frame to account for correlations between them [71].

The wind integration studies report that it is important to base the wind power production pattern on prospected locations of wind farms, to include the effect of interconnectors, and to analyze multiple years. Hasche et al. conclude that at least 5 years should be analyzed with a minimum time step of 1 h to arrive at a representative value [69].

4. How to model IRES impacts on low-carbon power systems

4.1. Detailed modeling of IRES impacts

We recommend using a unit commitment and economic dispatch (UCED) model to accurately simulate IRES impacts, as it simulates actual practice. A separate power system reliability model is only required for determining the capacity credit. The UCED model can determine the costs, emissions, and remaining flexibility in the system. The model should at least account for:

- IRES power production time series. These should have a time step that is smaller than or equal to the time step of the model, they should reflect the geographic distribution of the IRES resource, and they should span the same year and period as the load time series.
- Flexibility constraints of thermal generators, including must-run statuses and part load efficiencies.
- At least a 1-h time step. Extreme events can be simulated with a smaller time step.
- System reserves. The reserve sizing methodology should ensure a pre-set level of reliability.

In addition to these fundamental elements, modeling recommendations have been made in Section 3 for specific impacts. Common modeling elements include interconnection capacity and efficient reserve sizing.

Other ways of increasing system flexibility may also be considered when studying a low-carbon power system. In such a system, novel concepts such as high-capacity interconnectors, electricity storage, large-scale DSM, and large numbers of gas turbine peaking plants could be economic options.

4.2. Crude modeling of IRES impacts

Integrated assessment models and energy system models are limited in the level of detail they can model, so processes are often included by using aggregated parameters that describe general trends (e.g., [72]). To enable the modeling of IRES power system impacts, an overview of indicators was compiled that summarizes the general trend of the power system impacts (Table 8). These trends are based on the reported power system impacts of wind power from Tables 2 to 7 and Figs. 4, 5, and 8, because too little information is available for solar PV and wave power.

The representativeness of wind impacts for other IRES depends on the similarities between three properties of IRES: the variability, forecast accuracy, and the generation pattern at daily and yearly scales.

The (GCSI) variability of solar PV and wind energy power production shows small differences (Appendix B). The total variability of solar PV power output, including changes resulting from the daily and seasonal cycles of the sun, is higher than the variability of wind, which results in a larger impact on thermal generators. Compared to wind power, the forecast accuracy of solar PV is slightly lower. The required reserve size for solar PV may thus be (slightly) larger than that for wind power [41].

The variability of wave power is unclear at short timescales, although some types of generators will buffer variability at time frames of seconds. At the hour level, its variability is reportedly smaller than that of wind power [36].

The daily and seasonal IRES generation patterns show the largest difference. Wind power output is tens of percentage points

Table 8
Overview of indicators that quantify the power system impacts of wind power.

Power system impact of wind	Value at 20% wind penetration, (reported range)	Function/observations	Valid for wind penetration levels up to	Range[a]
Reserve size: primary reserve	0.6%, (0.3–0.8%) of installed wind capacity (MW)	$y=0.015x+0.002$[b]	50%	±50%
Reserve size: combined secondary, tertiary, and hourly reserve	7%, (6–10%) of installed wind capacity (MW)	$y=0.20x+0.03$[c]	50%	±30%
Curtailment	~0% of produced wind power (MWh) [c]	0.5% at 30% penetration[d] 3.5% at 50% penetration[d]	50%	±40%
Efficiency reduction of thermal generators	4%, (0–9%) of nominal electric efficiency	4% at 35% penetration	35%	±100%
Displacement of thermal generators	Mainly natural gas, some coal	n/a[e]	35%	n/a[e]
Capacity credit	16%, (5–27%) of installed wind capacity (MW) is ELCC	A decrease in capacity credit of 0.4% per 1% increase of wind penetration level[f]	30%	±100%

[a] The range is based on the deviation of modeled values from the average values shown in the columns "value at 20% wind penetration" and "function/observations".
[b] Based on the values underlying Fig. 4. Studies that based the reserve size on wind variability were not included, as they may underestimate the reserve size. The function has a fit of $r^2=0.61$. y=reserve size in MW, x is installed wind capacity in MW.
[c] Based on the values underlying Fig. 5. The UK-S and GER-F studies were not included because they do not supply the reserve size of the reference system, so the relative increase could not be determined. The function has a fit of $r^2=0.64$. y=reserve size in MW, x is installed wind capacity in MW.
[d] The reported curtailment values only show curtailment resulting from low-load, high-IRES oversupply situations. Curtailment resulting from grid constraints is very region specific.
[e] Displacement is dependent on the merit order and residual demand, which are both very region specific. Displacement can therefore not be described by a quantitative function.
[f] Based on the values from Fig. 8. Reported capacity credits show a wide range, so only basic trends could be identified.

higher in the morning and in winter [34]. Solar PV production peaks in the middle of the day, and during summer. As such, it correlates better with load, increasing the capacity credit, and decreasing curtailment [73]. Average wave power production is rather constant during the day, but large changes can be observed between months [36,40,74].

The integration of more than one type of intermittent resource reduces the power system impacts of intermittent power, because wind, solar PV, and wave power are weakly correlated, which leads to smoothing of the combined power production [17,36,75].

4.3. Cost modeling of IRES impacts

IRES power system impacts affect the total power system costs, as quantified by almost all IRES integration studies. Three approaches can be identified:

(1) Most studies quantified the operational costs (consisting of fuel, variable O&M, CO_2 costs, and sometimes start-up/value of lost load costs) of a reference power system, and a power system with IRES with a UCED model. These studies show that the operational costs decline at higher levels of wind penetration, because fuel and CO_2 costs decrease. No costs are allocated to the specific power system impacts of wind [6,7,12,14,21,30].
(2) In addition to the operational costs, two integration studies have also determined the investment costs (consisting of investments in IRES, thermal capacity, and sometimes transmission lines) for a more comprehensive cost/benefit analysis of IRES [13,24]. Two other studies have determined the costs and benefits of a low-carbon energy system at large, without determining the specific cost effects of wind power [3,17].
(3) Lastly, a number of studies have specifically quantified one or more of the costs/benefits of the power system impacts of IRES, as shown in Table 9 [8,10,13,15,26–28].

In this third group, six mechanisms have been determined that affect the costs of the power system. Extra costs are incurred by additional balancing, grid investments, power plant cycling, and investment and maintenance of wind power. Benefits arise from fuel and CO_2 credit savings (which exceed the additional fuel use due to extra flexibility) and a capacity credit of wind power (which reduces the investments in thermal capacity) [11,26]. Of the six power system impacts, only the larger reserve size has a direct effect on costs. The capacity credit has a long-term effect on costs as fewer capacity investments are needed. The other three impacts have an indirect effect: they affect the extent to which fuel savings are realized.

An overview of the additional costs of wind power is shown in Table 9, except for investment and maintenance costs of wind power, which are already widely reported elsewhere (e.g., [1,4]). Balancing costs result from the extra reserves needed to balance wind as indicated in all reports, except for the US-EWITS report, in which the cost of suboptimal dispatch of thermal capacity, resulting from the uncertainty of wind, is also included. The costs

Table 9
Overview of wind integration costs from the literature.

Study	IRES penetration (%)	Cost effect (€$_{2010}$/MWh$_{IRES}$)	Calculation methodology
Balancing costs			
Wind power			
GER-F	35	2.4–5.8[a]	The increase in reserve costs of a UCED simulation between a scenario without and with wind
UK-S	19	2.7–4.8[b]	Volume of extra reserves is calculated statistically and multiplied by the simplified costs of reserves
US-ERC	25	−0.1–0.2[c]	Volume of extra primary reserves is determined statistically and multiplied by the calculated cost supply curve of reserves for the ERCOT area
US-EWITS	20	3.4	The increase in costs from a UCED simulation with perfect foresight from a simulation that accounts for a forecast error of wind
US-MIN	25	0.5	The cost effect of increasing the combined reserve size from 5% of peak load to 7% of peak load is simulated using a UCED model
IEA Task 25	< 20	1.0–4.2	Review of literature up until 2008[d] [11]
Gross et al.	20	< 5.0	Review of literature up until 2005[d] [16]
Solar PV power			
US-AR	8	2.2	The increase in reserve costs of a UCED simulation between a scenario without and with extra solar PV reserve requirement
Transmission investment costs			
Wind power			
GER-F	35	1.4–5.7[e,f]	Review of literature up until 2007
UK-S	19	2.3–4.5[e]	Based on estimates of National Grid, the TSO of Great Britain
IEA Task 25	< 20	0–7.7[e]	Review of literature up until 2008 [11]
Thermal power plant cycling costs			
Wind and Solar PV power			
US-WWSIS2	33	0.1–0.5[g]	The increase in power plant cycling costs of a UCED simulation between a scenario without and with wind and solar PV power

[a] Detailed figures are based on the original source, which is the PhD thesis of the author [76].
[b] Costs calculation was adopted from Task 25 and corrected for inflation [11].
[c] Costs are low because only primary reserves are considered. Higher wind penetrations lead to units higher in the merit order providing regulation reserve, which is cheaper. This results in a decrease in costs compared to the reference (0% wind) case.
[d] The Task 25 study considered 10 cost reports and Gross et al. 23 reports. 4 reports were considered by both.
[e] Converted from €/kW to €/MWh assuming a 40-year transmission cable lifetime, a 7% discount rate, and an annual load factor of 30% [4].
[f] These costs account for grid reinforcements that are necessary because of wind power. If the connections to the wind farms are also included, the costs increase to 7.1–20.0 €/MWh for offshore wind power.
[g] Cycling costs mainly consist of extra start-up costs. The lower range applies to a scenario with 16.5% penetration of each IRES. The high range applies to a scenario with 25% solar PV and 8% wind power.

typically range between 1 and 5.8€/MWh when disregarding those of US-ERC (which only considers primary reserves). The range can be attributed to the different reserve sizing approaches and regional differences. Transmission investment costs also show a large spread, because they depend on the location of the wind farm and load centers, as well as on the existing transmission capacity. The onshore estimates of GER-F are very similar to the figures of an IEA Task 25 overview study of operating systems with large amounts of wind power [11]. Overall, both costs appear to be at most 4.5–7.7€/MWh, constituting less than 10% of the wholesale electricity price [11].

The benefits of wind power were analyzed by two studies: UK-S calculated the effect of wind power on the national electricity price. The capacity credit and fuel savings reduce the price by 4.1€/MWh, which is double the costs related to balancing and transmission investments (1.9€/MWh). The largest cost factors are the investment and maintenance costs, which increase the electricity price by 5.9€/MWh. US-EWITS calculated that the fuel saving benefits were 1.2–1.4 times the costs related to balancing and transmission investments, without specifying the cost per MWh.

5. Discussion

5.1. Crude modeling of IRES impacts for low-carbon power systems

The crude modeling recommendations of this paper are largely based on studies of power systems resembling present-day systems. Present-day systems are characterized by (1) large shares of conventional thermal generation, (2) present-day market designs, and (3) low shares of novel technologies such as high-capacity interconnectors, electricity storage, and DSM. We used present-day systems to draw conclusions about low-carbon power systems, because only four studies consider low-carbon scenarios: EU-EWI, GER-H & IR-M simulated a 50–70% reduction, and ECF simulated a 95% reduction (without specifically discussing the impacts of IRES) [7,17,20,24]. All four studies stress that future low-carbon power systems will need the aforementioned novel technologies to increase system flexibility. These technologies can also increase the match between IRES production patterns and (inter)national load profiles [8,24]. Moreover, they show that these technologies can reduce the IRES impacts on the power system. On the other hand, if low-carbon technologies such as nuclear power and CCS are inflexible, they could exacerbate the impacts. The reported power system impacts, as shown in Table 8, should therefore be taken as a starting point, and new technologies to increase system flexibility should be included when modeling low-carbon power systems.

5.2. Comparing IRES integration studies

There are three reasons that make it difficult to compare the reported power system impacts of the integration studies. First of all, the generator mix, IRES generation patterns, and market design are unique per region. They all affect the magnitude of the IRES impacts. Secondly, the studies use different starting points for determining the impacts. For example, reserve sizes have been based on varying reliability targets and forecast horizons. Thirdly, different methodologies have been used in the studies to quantify the power system impacts. Four reserve sizing approaches are distinguished, as well as two capacity credit calculation methodologies and three different approaches for calculating the efficiency reduction of thermal generators. The difference in outcome between some methodologies is small (capacity credit, $\sim$10% difference), whereas it is large between others (reserve size, up to 100% difference). Because of the multitude of factors affecting the magnitude of the impact, it is difficult to attribute a change in impact to one factor. For example, it is impossible to determine which of the three factors predominantly causes the combined minute and hour reserve size of the US-MIN study to be about half the reserve size of the IR-M and US-SPP studies.

5.3. Power system impacts of solar PV and wave power

A high penetration of IRES in a low-carbon power system will most likely be realized with a mix of wind, solar PV, and, potentially, wave power [3,17]. Our review of wind and solar PV impacts shows that these are largely comparable, but that there are some differences (e.g., in curtailment and capacity credit). More studies on the impacts of solar PV and wave power are needed to assess their impacts, both as single technologies and as part of a portfolio of multiple types of IRES.

5.4. Distributing the costs and benefits of IRES

There is no agreement on how the costs and benefits of IRES should be passed on to the owners of IRES. The starting point is the importance of maintaining a level playing field for IRES and thermal generators alike. Currently, costs are passed on to all electricity consumers through tariffs [52], which also cover reserve and connection costs related to thermal generation. The benefits result in lower electricity prices. If the tariffs are mainly covering IRES costs rather than thermal generator costs, this would give IRES sources an advantage. Power system operations are complex, which makes it difficult to determine the cost for each generator in a transparent and workable way.

6. Conclusions

We have quantified how present-day power systems and their thermal generators are affected by the impacts of IRES, to gain more insight into the future power system impacts of IRES on low-carbon power systems and how these impacts can be modeled.

Based on studies on the power system impacts of IRES, both observed in real life and modeled by 19 integration studies, we conclude that in present-day power systems the impacts of IRES are sizeable, especially at a medium penetration level (20% of annual power generation). Reported impacts for wind power are as follows. The size of primary reserves increases by a modest 0.6% (0.3–0.8%) of the installed wind capacity, but the combined size of all other reserves increases by 7% (6–10%) of the installed wind capacity. Wind curtailment is primarily caused by transmission constraints: only at penetration levels of $>30\%$ does oversupply of wind power cause minor curtailment (0.4–3.5% of wind power generated). Wind power has a firm capacity of 16% (5–27%) of its total capacity. Thermal generators are affected by a reduction in their efficiency of 4% (0–9%), by displacement of (mainly natural gas-fired) generators with the highest marginal costs, and by the need to meet the increased demand for reserves. Of all impacts, only the increase in reserves incurs a direct system cost of 1–6 €/MWh_{IRES}. The capacity credit reduces the need for investments in the long term, and the remaining three impacts affect fuel savings resulting from wind power.

Current IRES integration studies have only considered the impacts on power systems resembling present-day power systems. Future low-carbon power systems will be different in terms of generator mix and possibly market design, thus affecting the impacts on both the power system and its thermal generators. This study has identified a number of power system elements that should be included to accurately model IRES and their impacts. Using a unit commitment and economic dispatch model is recommended, as it simulates actual practice and can explicitly model IRES power system impacts. The model should include four

fundamental elements: a time step of < 1 h, detailed IRES production patterns, interconnection capacity, and flexibility constraints of thermal generators. Half of the integration studies included all of these. In addition, modeling of the uncertainty associated with IRES production is also recommended, besides using an efficient reserve sizing methodology, which was carried out by four studies out of 19. Lastly, novel power system technologies, such as high-capacity interconnectors, electricity storage, large-scale DSM, and large numbers of gas turbine/gas engine peaking plants, should also be considered, as they add flexibility to the power system and can become economic options. None of the studies considered two or more of these novel options.

A limitation inherent to this study's approach is that its results and recommendations are based on observations and simulations of systems resembling present-day power systems. Future IRES integration studies for low-carbon power systems need to better identify the IRES power system impacts on low-carbon systems, and how to model them. This study provides methodological guidelines for such future studies. Modeling of low-carbon power systems will also provide more insight into their operations, which may improve the alignment between present-day decisions on investments or market designs and the long-term vision of a low-carbon power system.

Three other research gaps also require more detailed modeling of a low-carbon power system. Firstly, research is needed on how low-emission thermal power plants are affected by large-scale intermittent renewable sources in a low-carbon power sector. Areas of attention are the load factor, profitability and reduction in efficiency of the thermal power plants, whilst also accounting for flexibility constraints. Secondly, the integration of large-scale solar and wave power in power systems needs to be further investigated. Special focus should be given to identifying differences in power system impacts between the different types of IRES and the combined power system impact of a portfolio of wind, solar PV, and wave power. Thirdly, further research is needed on a consistent methodology to determine the costs and benefits of IRES for power systems. Based on this methodology, the allocation of system costs between generators can be settled. Thus, the methodology must ensure a level playing field for all types of generators.

Acknowledgments

This research was carried out in the context of the CATO-2-program. CATO-2 is the Dutch national research program on CO_2 Capture and Storage. The program is financially supported by the Dutch government (Ministry of Economic Affairs) and the CATO-2 Consortium Parties. The authors would like to thank Özge Özdemir and Marlies Kamp for their feedback.

Appendix A. Definitions of concepts

Penetration level of an IRES technology (%) is the yearly electricity production of an IRES in a certain geographic area (TWh yr^{-1}) divided by the total yearly electricity demand in this area (TWh yr^{-1}).

Load (MW) is the electricity demand in a certain geographic area for a given point in time.

The change (ΔP) in power output of a renewable electricity generator type (MW) is the difference in power generation by this generator type between two subsequent points in time.

The variability of a renewable electricity production by a generator (σ) is the standard deviation of a collection of deltas with an identical time step from the mean value. The mean value is typically zero, as positive and negative ramps will cancel each other out. The relative variability is described as the standard deviation per MW of installed nameplate capacity of this generator per year. For solar PV, the variability can also be expressed as a percentage of the Global Clear Sky Index (GCSI), which expresses the potential electricity production under cloudless conditions as a percentage of the nominal capacity.

Balancing time frames are specific time periods for which the balance between load and generation within an electricity system can be evaluated. In this study we distinguish three balancing time frames, namely seconds (1–60 s), minutes (1–60 min), and hours (1–4 h). For these time frames, primary, secondary/tertiary, and hourly reserves are required, respectively, to maintain the balance [77].

Operational properties are the technical properties of electricity generation technologies that influence the pattern of electricity generation over time. The most important properties for thermal power plants are the ramp speed (MW min^{-1}), part load efficiency (%), minimum load level (% of max load), and the start-up time (h).

Curtailment of IRES (%) occurs when not all electricity generated by an IRES source can be used. It is defined as the percentage of discarded power (TWh yr^{-1}) compared to the potential renewable electricity generation in an unconstrained system (TWh yr^{-1}).

A control area is the ENTSO-E term for a geographic area with a single transmission system operator (TSO), in which physical loads and controllable generation units are connected with each other. In the United States, this is known as a Balancing Authority Area.

A synchronous area consists of one or more control areas, which are interconnected. The system frequency is uniform within the whole area [21].

A reliability index expresses to what extent the power system can meet electricity demand. The most common indices are the Loss Of Load Expectation (LOLE, the amount of energy not served over a certain time period as measured in hours per year) and the Loss Of Load Probability (LOLP, the risk that power cannot be delivered over a certain time period as a percentage). They are calculated by comparing the historical or forecasted load and production over the course of one or multiple years [11].

Power system flexibility is “the ability of the aggregated set of generators to respond to the variation and uncertainty in net load” [9]. As such, it refers to multiple properties of the power system, such as the overall ramp speed [MW/h] and minimum load (expressed as a percentage of the peak load).

Demand side management consists of arrangements between grid operators and electricity consumers to adjust electricity demand according to electricity generation. Its goal is to better match electricity demand and supply in order to operate the power system more efficiently.

Wind power forecast accuracy is defined as the square root of the average squared forecast error: the root mean square error (RMSE). It is expressed as a percentage of the actual wind power production [44]. The forecast accuracy is dependent on the forecast horizon. Day ahead forecasts are often used for unit commitment decisions.

Low-carbon power systems are composed of large shares of low-carbon generators such as renewable, nuclear, and electricity generators using CCS technology in order to reduce the power sector's CO_2 emissions by 50–80% compared to 2005 emissions levels.

Appendix B. Relative variability of IRES

The relative variability of wind power output

Relative variability at a time frame of seconds

The relative variability of the power production of a wind farm at an interval of one second is quite small: the change in output of

single wind farms between two successive seconds showed a standard deviation that ranged between 0.05% and 0.18% of nameplate capacity (NC) [78,79].[5] The variability at this interval is due to very local, small random changes in wind speed that affect single wind turbines [38]. Part of these variations is leveled out by the inertia of the turbine, which causes smoothing of rapid changes in power output at small time intervals [80].

At an interval of under 1 min, Ernst [35] reports that the changes in power output between turbines are uncorrelated based on German wind power production observations. Thus, increasing the number of turbines decreases the relative wind power variability at this time interval [81]. This is shown by a decrease in standard deviation to about 0.04% of N.C. when the seven US wind farms are evaluated together.

Relative variability at a time frame of minutes

A distinction can be made between the relative variability of power production at intervals of approximately 1–5 min and 10 min and longer. The changes in power output of a wind turbine at the 1–5 min interval, similar to the seconds interval, are caused by local random changes in wind speed [10]. Consequently, the changes in power output of different wind turbines are nearly uncorrelated, as is confirmed by Kirby for a 1-min interval [77]. The measured standard deviation of a single wind farm for a 1 min interval (σ=0.3–1.7% of NC) decreases when all seven wind farms are aggregated (σ=0.3% NC)[6] [78,79].

The trend of increasing variability with larger time frames continues for changes at an interval of 5 min, as measured at a single US wind farm (σ=3% NC) [78]. According to Ernst, who analyzed the wind power production in Germany in 1998, the correlation between the power output of wind farms is still weak at this interval (the correlation coefficient is less than r=0.2 for distances $<$5 km) [35].

The variability of power production by wind farms at 10–60 min intervals is higher than for 1–5 min intervals for the following two reasons. Firstly, on average the wind speed changes more at longer time intervals. Secondly, the changes in power output of turbines at longer intervals are caused by weather fronts that affect all turbines the same way, rather than by local wind conditions [34]. As a result, the changes in power output of individual turbines in a wind farm are more correlated [10,35]. The higher correlation means that power output changes of single turbines stack up to a larger extent at a wind farm level, resulting in a larger variability of the total farm. The standard deviation of wind power output of a single wind farm is 1.8–4.8% NC, which decreases to 1.1% NC for the seven aggregated farms at a 10-min interval [78,79].

Relative variability at a time frame of hours

At a time frame of 1 h the standard deviation of the variability of a single wind farm (σ=3.5–11.6% NC) is still reduced when the output of multiple wind farms is aggregated (σ=2.9% NC), but to a lesser extent [79]. These observed standard deviations are in the same order of magnitude as those observed in the Southwest Power Pool area in the U.S., where the average change in power output at an hourly interval is 4% of nameplate capacity, and 98% of all variations are sized smaller than the 12% of wind nameplate capacity [29].

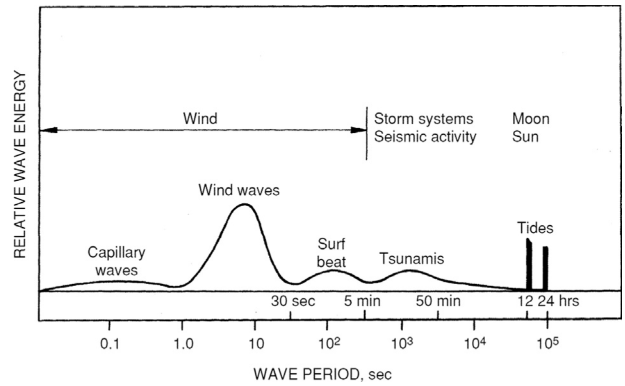


Fig. 9. Overview of the relative wave energy as a function of the wave period [85]. *with kind permission from Springer Science+Business Media B.V.*

Predictability of wind power production

A number of factors influence the forecast error, including the forecast horizon, the area size for which power production is predicted, the "prediction difficulty" of the landscape, and the forecast method [43,82].

The relative variability of solar PV output

Solar PV variability results from two processes. The daily trajectory of the sun introduces a fluctuation inherent to the technology, which can lead to changes in output of 10–13% at a 15-min interval between sunrise and sunset. This highly predictable change in output is dependent on the season, and shows a very high correlation among solar PV installations in a given area [83]. Secondly, clouds can obstruct the direct irradiation of solar PV panels by the sun. Cloud formations are much less predictable and the correlation between changes in output resulting from clouds is smaller, especially for larger areas.

Below, the insolation is used as a proxy for solar PV power output to determine the relative variability, because a comprehensive insolation dataset is available [41]. Insolation is an accurate proxy, even at very short time intervals [83]. Moreover, the relative variability of solar PV power production is expressed as a percentage of the Global Clear Sky Index (GCSI). This way, only the stochastic variation caused by clouds is accounted for, and not the deterministic variation resulting from the changing position of the sun [41]. The latter variation can be fully predicted and integrated in power plant schedules.

Relative variability at a time frame of minutes

At a 1-min time frame, insolation variability is strongly reduced by aggregating the power production of single sites (σ=8% of GCSI; together σ=2%).[7] This is the result of changes in power output already being uncorrelated at very small distances [41,84]. At a time frame of 10 min, the same pattern can be observed (single site σ=11%, aggregate σ=3%). The correlation between neighboring sites becomes stronger at this interval, but it still drops to zero for distances over 50 km [41]. One should note that for time frames of 60 min and shorter, the distributions of changes in GCSI have "fat tails" compared to a normal distribution: large changes are more prevalent than a normal distribution suggests [41].

[5] The ranges of the average change in output and standard deviation figures in Section 3.2 are observed values of seven wind farms in the U.S., unless stated otherwise. Data of all sites were recorded for a single year, sometime in the period 2001–2003. The stated percentages are based on the monthly averages reported by Wan, and the yearly average reported by Parson et al. They are expressed as a percentage of the nameplate capacity and apply to both upward and downward changes.

[6] Note that the relative variability is discussed in Section 3. When aggregating the power production of wind farms, the relative variability [σ or $MW_{change}/MW_{windcapacity}$] will decrease. The absolute variability [MW] will increase, because the correlation in power production is typically $>$0.

[7] Variability figures in this section are based on measurements at 23 sites in the U.S. for the year 2004.

		Input data per timestep	Number of patterns, approach	Calculation method	Reserve size determined per
Basic statistical approach	(Stat-B)	Load forecast error Wind variability/ forecast error	Single (historic) → Deterministic	Statistical	Whole modeling period (typically 1 year)
Dynamic statistical approach	(Stat-D1)	Load forecast error Wind variability/ forecast error	Single (historic) → Deterministic	Statistical	Time step (typically 1 hour)
	(Stat-D2)	Load forecast error Wind forecast error Power plant outage probability	Single (historic) → Deterministic	Statistical/ Probabilistic	Time step (typically 1 hour)
Stochastic approach	(Stoch)	Load forecast error Wind forecast error Power plant outage probability	Multiple (Monte Carlo) → Stochastic	Statistical/ Probabilistic	Time step (typically 1 hour)

Fig. 10. Schematic overview of reserve sizing approaches.

Relative variability at a time frame of hours

At intervals of an hour and larger, the relative variability becomes larger, and the correlation of the change in insolence among panels becomes stronger, especially at short distances (Fig. 3). The relative variability of insolence at a single site ($\sigma = 13\%$) and at all sites ($\sigma = 5\%$) increases at an interval of 1 h. For an interval of 180 min, the relative variability of insolence at all sites increases to $\sigma \approx 9\%$. This is slightly lower than the relative variability of wind ($\sigma \approx 11\%$ change in the same area) [41].

The relative variability of wave power output

For wave power, different types of waves can be distinguished on the basis of their period (the time it takes to complete a single cycle), as shown in Fig. 9. Wind waves and tides contain relatively most energy; hence these cycles are used for electricity generation. Wind waves, generally known as waves in the context of wave energy, are created by the wind on the surface of a body of water. The top layer of a body of water absorbs part of the kinetic energy of the wind, which is converted to potential energy (water displaced from the mean sea level) and kinetic energy (motion of water particles) [39]. Wave energy is captured from waves that have periods between 1 and 30 s, with the largest share between 5 and 15 s [85]. The electricity production depends on the wave period and the wave height, as well as the wave energy generator technology.

Relative variability at a time frame of seconds to minutes

Little information is available on the variability of the power output at intervals of seconds and minutes, partly as a result of a lack of measurements [39]. Changes in electricity output are likely to occur at second and minute intervals, and these could be comparable to the variability of wind power. As with wind power, the variability in power output of a wave farm will be relatively smaller than that of a single generator [86]. Moreover, wave power generators with an intermediate energy conversion step[8] could reduce the variability at a second interval. The intermediate step can serve as an intrinsic short-term storage process that filters out fast fluctuations [86].

[8] Some generators use a working fluid that is pressurized by wave movement, and subsequently drives the generator.

Relative variability at a time frame of hours

Wave power shows hourly variability, but it is smaller than that of wind power [40]. The hourly standard deviation for a location off the coast of California over a period of 16 years has been reported to be 10.8% for wind and 5.1% for wave energy [36].

Geographic variability

A comparison of the geographic correlation of wave and wind power for the US West Coast showed that wave energy production at two separate locations correlates more strongly than wind power production. Wind power production showed low correlations ($r < 0.25$) at a distance of more than 300 km, while wave power showed a correlation of $0.25 < r < 0.50$ for this distance. In addition, wave power correlations were stronger compared to the correlations of wind power for shorter distances [36].

Appendix C. Reserve sizing methodologies

To balance variations in IRES power production, the forecast horizon is important. For short horizons (< 1 h), persistence forecasts are used, which assume that the current power output is the same as the power output in the future [87]. For these horizons, the deviations from the status quo are balanced. The required reserve size thus equals the expected variability. For longer time horizons, forecasts are made with wind prediction models. These models have a forecast error that becomes larger as the forecast horizon becomes longer. In current power systems operation, generation schedules are made 12–36 h before power needs to be generated, based on the forecasts of load and wind power production. Based on more accurate forecast information, these schedules are updated until a predefined time before delivery, which depends on the market design. After this point in time, emerging forecast errors are balanced with reserves up until the moment of power delivery [14,52].

Starting point for all four approaches is that the reserves have to be large enough to cover a predefined share (depending on the study, 70–99.99%) of the unpredicted changes in load and wind power output at their balancing interval. The remaining changes are balanced by curtailing wind power and contingency reserves [12]. In addition, almost all studies calculate the reserve size for the combined uncertainty in load and wind fluctuations. This is relevant,

because the sum of the separate reserves required to balance fluctuations in either load or wind is larger than the combined size, as forecast errors for load and wind are uncorrelated [88]. Lastly, this overview provides the average reserve size of both up-reserves and down-reserves. In some studies the reserve size is actually symmetrical, while others report the average of the up- and down-reserves. A schematic overview of the differences between the approaches is shown in Fig. 10. Below, we will briefly discuss the four approaches.

(1) In the first, "*basic statistical approach*" (called Stat-B), the fixed size of the non-event reserve is calculated based on historical time series of load and wind. The error-distribution of load forecasts is determined, as well as either the distribution of wind power production variability or the error-distribution in wind forecasts for the considered balancing interval. The type of wind distribution used depends on the study: some studies use the distribution of variability (Stat-B-VAR), assuming that fluctuations are balanced as they happen. Others state that the reserve size has to be determined during dispatch, which occurs before balancing takes place. With this latter approach, wind and load forecasts are used, the error of which has to be balanced by reserves (Stat-B-WLF). Next, the load and wind distributions are combined into a single error-distribution, treating load and wind as independent variables. The non-event reserve capacity is then sized such that it covers the share of forecast errors that equals the required reliability, e.g., 99.7%. Advantages of this approach are the methodological simplicity and the simple description of the required reserve size. The key disadvantage is the over-dimensioning of the reserve size: the size is fixed at the maximum requirement for the whole year, so part of it is redundant during low-wind situations.

(2) In the second, "*dynamic statistical approach*", the non-event reserve size is not set at a fixed annual size, but expressed as a function of the wind power production and load pattern used in the UCED model. The reserve size is thus calculated per time step of, e.g., 1 h. This can be done in two different ways. Stat-D1: datasets of wind and load forecast errors, and a dataset of the concurrent wind power production and load, are used to identify statistical trends. Based on these trends, a rule of thumb that describes the non-event reserve size is formulated such that the predefined system reliability criterion is met. The rule, which in its simplest form describes the reserve size as the sum of x% of expected load and y% of expected wind power, is used as input for the UCED model. The main advantage of this approach is that with the same input data as used for the Stat-B approach, a smaller reserve size is determined that still meets the reliability target. The methodology is more complicated, however. Stat-D2: the reserve size is a term in a formula that expresses the reliability of the power system, so that the minimum reserve size can be calculated for a pre-set reliability level. The formula defines the risk of the power system not being able to meet all electricity demands as a function of the reserve size, the standard deviation of the total system forecast error (composed of the forecast errors of load and wind power), and the probability of unplanned power plant outages. Hence, this approach is probabilistic in nature. All factors except for the reserve size are known, so that the only unknown factor, the reserve size, can be calculated for each time step and used as input for the UCED model [89]. Advantages of this method include the efficient reserve sizing and the incorporation of the risk of power plant contingencies. The disadvantages of this approach are larger data requirement and the more complicated methodology.

(3) In the third, a "*stochastic approach*" (Stoch) is used in the WILMAR model, which is used in the IR-M study [7]. This approach resembles the Stat-D2 approach, but is stochastic in nature, rather than deterministic. The size of combined non-event and contingency reserves with a balancing time frame ranging from 5 min to 36 h is determined per time step by a stochastic sub-model and then used as an input for the UCED model. This sub-model computes distributions of the size of the wind and load forecast errors by means of a Monte Carlo analysis, based on their historical time series and forecast accuracies. A similar distribution is computed for the size of power plant outages, based on power plant availability statistics. These three distributions are combined, and the reserve size is defined such that it is large enough to cover a predefined percentage of all forecast errors and outages [7,48]. Advantages are the efficient reserve sizing, the inclusion of power plant contingencies, and the robustness of the results. However, the data requirement is larger, and the methodology is more complex than any of the other approaches.

(4) In the fourth approach, the utilized reserves are calculated in retrospect (utilized). The UCED model is run with enough reserves to cover all imbalances, and afterwards the amount of utilized reserves is determined. With this approach the very minimum of reserves that are required in the system are quantified in a straightforward way, but the results do not account for the uncertainty that power system operators face in reality.

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